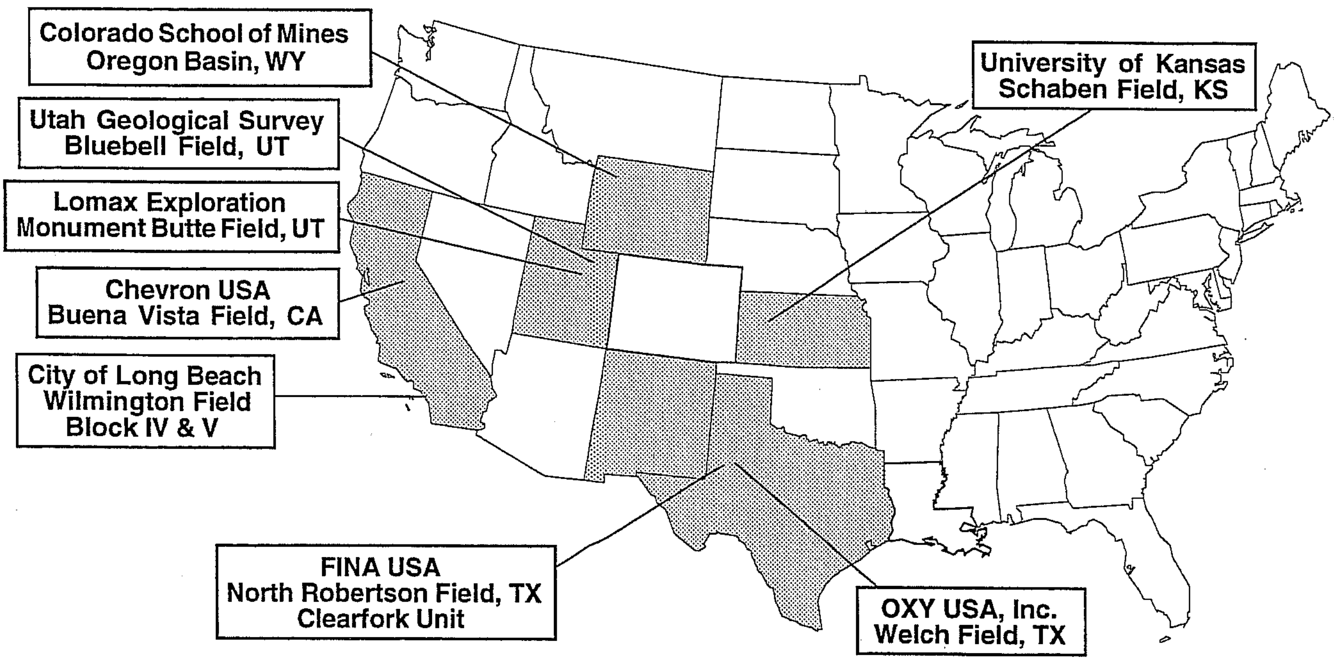
Advanced Applications of Wireline Logging for Improved Oil Recovery Workshop

Denver, Colorado
January 13, 1998

DOE Oil Recovery Projects Presented



NATIONAL PETROLEUM TECHNOLOGY OFFICE

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DEPARTMENT OF ENERGY · UNITED STATES OF AMERICA

Program

Advanced Applications of Wireline Logging for Improved Oil Recovery Workshop

Denver, CO January 13, 1998

Time	Title	Presenter	Affiliation
7:45 -8:00	Introduction		
8:00-8:45	Using Dipole Shear Anisotropy, Thermal Decay Time, and Isotope Tracer Logs for Recompletion Design and Post-Recompletion Evaluation in Complex Reservoirs	Craig Morgan	Utah Geological Survey
8:45 -9:30	Applying Integrated Formation Evaluation to Advanced Reservoir Characterization in California's Monterey Formation Siliceous Shale	Thomas Zalan	Chevron USA, Inc.
9:30-10:15	Combining Flow Theory and Multiple Log Readings to Improve Permeability Calculations	Archie Taylor	OXY USA Inc.
10:15 -10:30	Break		
10:30 -11:15	An Integrated Geologic and Engineering Reservoir Characterization of the North Robertson (Clear Fork) Unit, Gaines County, Texas	John Auman	D.K. Davies & Associates, Inc.
11:15-12:00	PfEFFER: The Integrated Analysis of Wireline Logs and Reservoir Data in a Spreadsheet Environment	John Doveton	Kansas Geological Survey
12:00-1:15	Lunch		
1:15 -2:00	Acoustic Logging Through Casing to Detect Hydrocarbons in the Wilmington Field, California	Dan Moos	Geomechanics International
2:00 -2:45	Application of Borehole Imaging Logs in the Green River Water Flood Demonstration Project	Dennis Nielson and Susan J. Lutz	Earth and Geosciences Institute
2:45 -3:30	Application of Borehole Imaging Logs to Eolian Reservoir Heterogeneity Studies, with an Example from the Tensleep Sandstone, Wyoming	Mary Carr	Colorado School of Mines
3:30 -3:45	Break		
3:45 4:40	Verification of Fracture Aperture Widths from Electrical Borehole Images Using Mudlog and Gamma Ray Correlations	Neil Hurley	Colorado School of Mines
4:30 -5:15	Overview of New Wireline Logging Technologies	Wayne Rowe	Schlumberger

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Workshop Context and Objectives

The U.S. Department of Energy (DOE) continues to actively pursue its goal of transferring to the petroleum industry critical information about technologies currently being applied in its Field Demonstration Program and other projects. DOE and BDM Oklahoma, with the aid of the Petroleum Technology Transfer Council, are teaming to provide industry with both a fresh perspective on technology use in these projects and a wide spectrum of practical applications of specific technologies. The Class Program field demonstration projects were selected to form the "core" of projects from which to draw for this practically oriented technology transfer effort. The objectives of this activity are to (1) identify technology advances and usable products demonstrated in Class and other program projects, (2) organize a series of workshops focused on technologies of significant interest and utility to industry, and (3) produce a published volume on each technology addressed in the workshop series. These workshops and their accompanying peer-reviewed volumes will not be technically or academically oriented treatments of the technologies, but "here's how we did it" and "here's how it worked" treatments in a case history context.

Selection Of Workshop/Publication Technologies

Two primary criteria were considered in selecting workshop topics and their order of presentation. First, technologies were considered that are playing important roles and are producing results in Class and related program projects. Second, technology areas were favored that have been recommended for research, development, and technology transfer by various recent surveys (both DOE-funded and non-DOE-funded and performed by both research-oriented and practical, industry-oriented organizations). Technologies identified jointly in both these considerations include wireline-log-related, seismic-related, and directional-drilling-related technologies.

The logistical feasibility of holding workshops for each of these technical areas was also considered, i.e., whether the application of the technology has proceeded sufficiently in program projects to warrant discussions of success or failure and overall project impact. Applying this criterion resulted in selection of wireline-log-related technologies as a first priority for treatment in this workshop and publication series.

Structure of the Advanced Wireline Logging Workshop and Publication

In Class Program projects, three categories of wireline log applications have contributed substantially to building accurate reservoir characterization models for implementation of improved recovery techniques:

USE OF ADVANCED WIRELINE TOOLS - Modern and newly developed tools such as nuclear magnetic resonance, pulsed acoustic, and array induction tools have likewise contributed to a better understanding of subsurface reservoirs in Class projects, particularly to a better knowledge of fluid distribution in the reservoir.

USE OF BOREHOLE IMAGING LOGS - Numerous projects have used borehole imaging logs to describe such diverse properties as lithologies, saturations in thin beds, sedimentary structures and reservoir architecture, and natural fracture orientation, aperture, and fluid content. Knowledge of the reservoir gained from these logs has contributed substantially to support reservoir modeling in several projects.

ROCK TYPING USING CONVENTIONAL LOGS - These approaches involving correlation of rock properties and fluid transmissibility properties to single or multiple wireline log response have enabled more accurate estimation of important reservoir performance-related properties on a fieldwide scale in some Class projects. This capability has resulted in a much more complete and less uncertain description of the reservoir on which to base recovery process implementation than would have been otherwise possible.

Primary objectives of the logging workshop are to:

- Bring out the decision making process that led to selection of the technology for use
- Convey the methodology for applying or implementing the technology
- Discuss technological successes and problems encountered
- Estimate the overall cost effectiveness of the technology

A published logging technology volume will be available within 12 months of the date of this workshop. This peer-reviewed volume will summarize the use of logging technologies in projects presenting at both the November, 1997 and January, 1998 logging technology workshops. It will also contain overviews of the technologies written and edited by technology experts and will have the same practical-applications focus as the workshops (panel discussion results at both workshops will be included in the volume). The volume will also contain information on the use of logging technologies in Field Demonstration Program projects other than those presented at the workshops. The volume will include material on newly developing advancements in the technologies that are still in the research stage as well, particularly on research and development activities being supported by DOE.

Overview of the Class Program

Philosophy and Context of the Class Program

The U.S. Department of Energy (DOE) has developed a coordinated strategic plan for all oil technology, natural gas supply, and related environmental research, development, and demonstration program activities. Individual program drivers stem from defined Federal Government roles to maintain reliable domestic energy supplies at reasonable costs; increase the value of Federal lands and U.S. Treasury revenues by maximizing production; provide science and technology leadership; enhance global market opportunities for U.S. energy technologies; and serve as a catalyst for industry, State, and other Federal agency partnerships. In this context, DOE's primary mission in the National Oil Program is to maximize the recovery of oil from known domestic reservoirs in an economically and environmentally sound manner, preserve access to this resource (i.e. to delay well and reservoir abandonments), and maintain U.S. competitiveness in the global marketplace.

Realizing that domestic production was declining rapidly and that huge volumes of oil were being abandoned in domestic reservoirs because of uneconomic production techniques, DOE initiated the Oil Recovery Field Demonstration Program in 1992. This program is one of the critical elements of the Oil Program necessary to move improved oil recovery (IOR) technology from concept through research, pilot-scale experiments, and full-scale field demonstrations to industry acceptance and commercialization. Both successes and failures of the field demonstrations provide focus to concurrent research programs. Elements of the field demonstrations that are suitable for broad industry application are communicated to the industry through the Oil Program's technology transfer effort.

Specific goals and objectives of the Field Demonstration Program include:

(1) Extend the economic production of domestic fields by:

- Slowing the rate of well abandonments
- Preserving industry infrastructure (including facilities, wells, operating units, data, and expertise)

(2) Increase ultimate recovery in known fields by demonstrating:

- Improved methods of reservoir characterization (both rocks and fluids)
- Advanced oil recovery and production technologies
- Advanced environmental compliance technologies
- Improved reservoir management techniques

(3) Broaden information exchange and technology application among stakeholders by:

- Expanding participation in DOE projects to include all industry sectors
- Increasing third-party participation and interaction throughout the life of DOE-sponsored projects
- Making technology transfer products user friendly

DOE is sharing with industry the cost of field demonstration projects in its Class Program. Class Program objectives focus on employing field demonstrations and intense technology transfer to bring newly developing technologies and ideas as well as innovative applications of proven technologies to rapid, practical, and widespread use. A primary emphasis is on state-of-the-art applications of promising and genuinely new tools and techniques that require externally funded trials to discover and develop the best application techniques for both technical and economic success. A second major emphasis is on innovative applications of existing technologies (i.e., applications of underutilized but cost-effective technologies).

Characteristics of the Class Program

A powerful and unique feature of the Class Program is that reservoirs with common geological origins have been grouped together for treatment under the program. The premise underlying the groupings is that geologically similar reservoirs will, to some extent, have similar reservoir characteristics and production problems. Therefore, this grouping system provides an analog basis for quickly applying successfully demonstrated technologies and methodologies to other reservoirs in the same group. These geologically based reservoir groupings were established by a study of reservoir information stored in DOE's Total Oil Recovery Information System (TORIS) database. The TORIS database contains data on more than 2,500 domestic oil reservoirs representing two-thirds of the known domestic oil resource, or about 360 billion bbl of original oil in place. Twenty-two distinct, depositionally defined reservoir groups (sixteen siliciclastic and six carbonate) are recognized in the TORIS database (see FIGURES 1 and 2).

As operators successfully demonstrate existing and new reservoir characterization and improved recovery technologies in field projects, other operators can confidently take advantage of the technologies in projects in analogous reservoirs. The greater the similarity the better; reservoirs in the same basin, or even within the same play (where deposits are most likely to be exposed to similar geologic conditions throughout their history), have a greater chance of being predictably similar. Of course, DOE recognizes the fact that every reservoir is unique in certain respects, and that no analogy will be perfect.

A second and perhaps more important feature of the reservoir groupings in the Class program, is that the reservoir groups have been prioritized by both the size of their remaining recoverable resource and the likelihood of reservoir abandonment in the near future. The Class Program consists of a series of industry cost-shared projects in these prioritized reservoir classes. By adhering to these priorities, those reservoir classes are being addressed first under the Class Program that will have the greatest impact on DOE's primary mission. Our country has no other mechanism to evaluate and coordinate such resource-directed priorities for technology development and demonstration projects. This is a unique contribution of this government-sponsored program, and a key reason for its existence.

Another unique aspect of the Class Program is its strong emphasis on technology transfer, which promotes widespread and rapid dissemination of the successes achieved in Class projects. Outside the Class program, successful technological developments achieved by individual oil companies or company coalitions are generally carefully guarded for the purposes of maintaining a competitive advantage. Industry, acting on its own, has no effective incentive to maximize technology transfer. By making information available to the entire industry, the government's Class Program has maximum impact on the goals and objectives of the Field Demonstration Program.

Cost-shared projects of the Class Program also serve as a source of risk abatement for final stage development of new technologies and novel applications of current technologies that might not attract funding from a risk averse industry. Outside the Class Program, although risk sharing is common in exploration ventures, there are few good mechanisms or incentives in place to persuade coalitions of small or large operators to duplicate these kinds of research ventures in mature production environments.

Current Class Program Projects

Cooperative agreements are in place for cost-shared projects in the three highest priority reservoir classes. Projects are cost-shared by DOE up to 50% of the total project cost. Nearly 30 projects representing combined industry and government investments in excess of $250 million are now in place. These first three reservoir classes contain more than half (126 billion bbl) of the 246 billion bbl of oil remaining in reservoirs listed in the TORIS database. Projects address either near-term (within five years) program goals of preserving access to reservoirs with high potential for increased productivity which are rapidly approaching their economic limit or mid-term (within ten years) program goals of developing and testing the best advanced technologies through an integrated multidisciplinary approach. Each project is divided into two budget periods. Projects that prove technical and economic feasibility during the first budget period are subsequently funded for field demonstration during the second budget period.

CLASS I Projects - Eleven projects (four mid-term and seven near-term) in Fluvial-Dominated Deltaic reservoirs were selected and awarded in 1992 and 1993(see FIGURE 3). Four projects have been completed.

CLASS II Projects - Nine projects (three mid-term and six near-term) in Shallow Shelf Carbonate reservoirs were selected and awarded in 1993 (see FIGURE 4).

Note that Class II is made up of shallow shelf carbonates characterized by both open and restricted circulation (see FIGURE 2). Although each of these subtypes has distinctive biological, sedimentological, and chemical characteristics, the two types are often gradational and it is frequently difficult to assign a given reservoir to one or the other type with confidence. The TORIS database lists about 64% of Class II reservoirs as of open circulation origin, and about 34% as restricted. The salient characteristic that both depositional environments share is rapid lateral changes in sediment character and associated energy levels. Class II reservoirs are among the most highly heterogeneous of carbonate reservoirs.

CLASS III Projects - Four near-term and five mid-term projects in Slope and Basin Clastic reservoirs were awarded in 1995. All of these projects remain active (see FIGURE 5).

Like the reservoirs of Class II, reservoirs of Class III are of more than one depositional type, being made up of both slope-basin and deep-basin clastic deposits (see FIGURE 1). Close similarities in the nature of deposits in these two groups compared to other clastic depositional groups justify lumping the two for treatment under the Class Program.

ADVANCED CLASS WORK Projects - This special series of projects deals with field-based reservoir characterization and recovery process projects aimed at refining advanced technologies that were demonstrated or identified in Class demonstration projects. In addition, technologies shown to be promising in laboratory research and development efforts (improved recovery methods and reservoir characterization technologies) were selected for demonstration under Advanced Class activities. The Advanced Class Work Program currently has three projects underway.

This workshop on logging technologies provides only a small sampling of the vast amount of practical information on technology implementation, reservoir characterization, and reservoir management that is available from Class Program projects. A good source of overview information is the *Class Project Summary Sheets*, a volume containing brief descriptions and status information on all of the projects, published by DOE. Similar overview information can be downloaded from the National Petroleum Technology Office website homepage (www.npto.doe.gov) in the form of the CLEVER (**CL**ass **EV**aluation **E**xecutive **R**eport) database. The *Class Act*, a DOE-sponsored newsletter, conveys highlight information on important project accomplishments and upcoming technology transfer events such as workshops, publications, and presentations. This and other DOE newsletters (*EYE on Environment* and *Inside Tech Transfer*) are also available at the website. Detailed project technical information may be obtained from interim project reports published by DOE and from numerous publications in professional journals. To obtain DOE publications relating to Class projects or for further information please contact:

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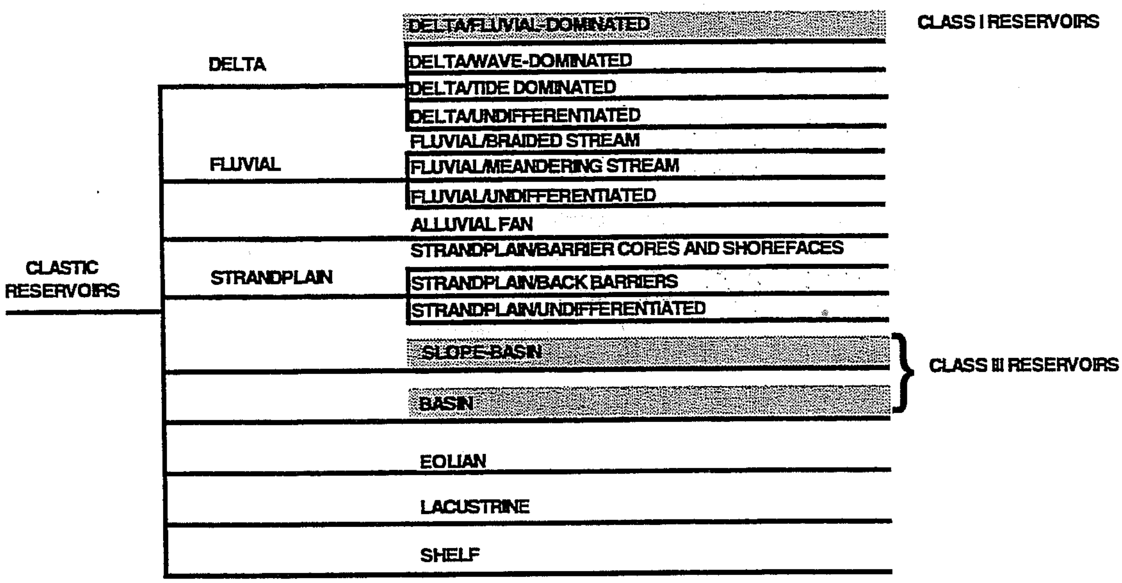


Figure 1 Geological Reservoir Groups (Clastics)

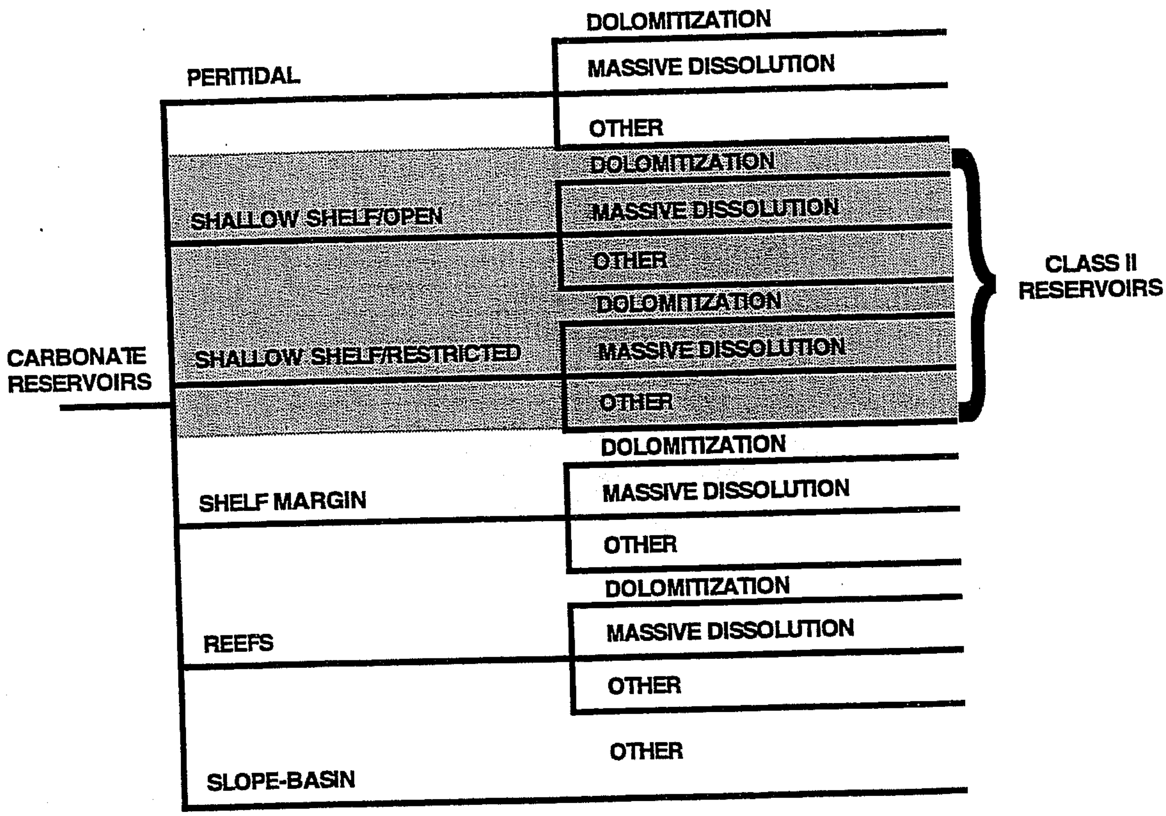


Figure 2 Geological Reservoir Groups (Carbonates)

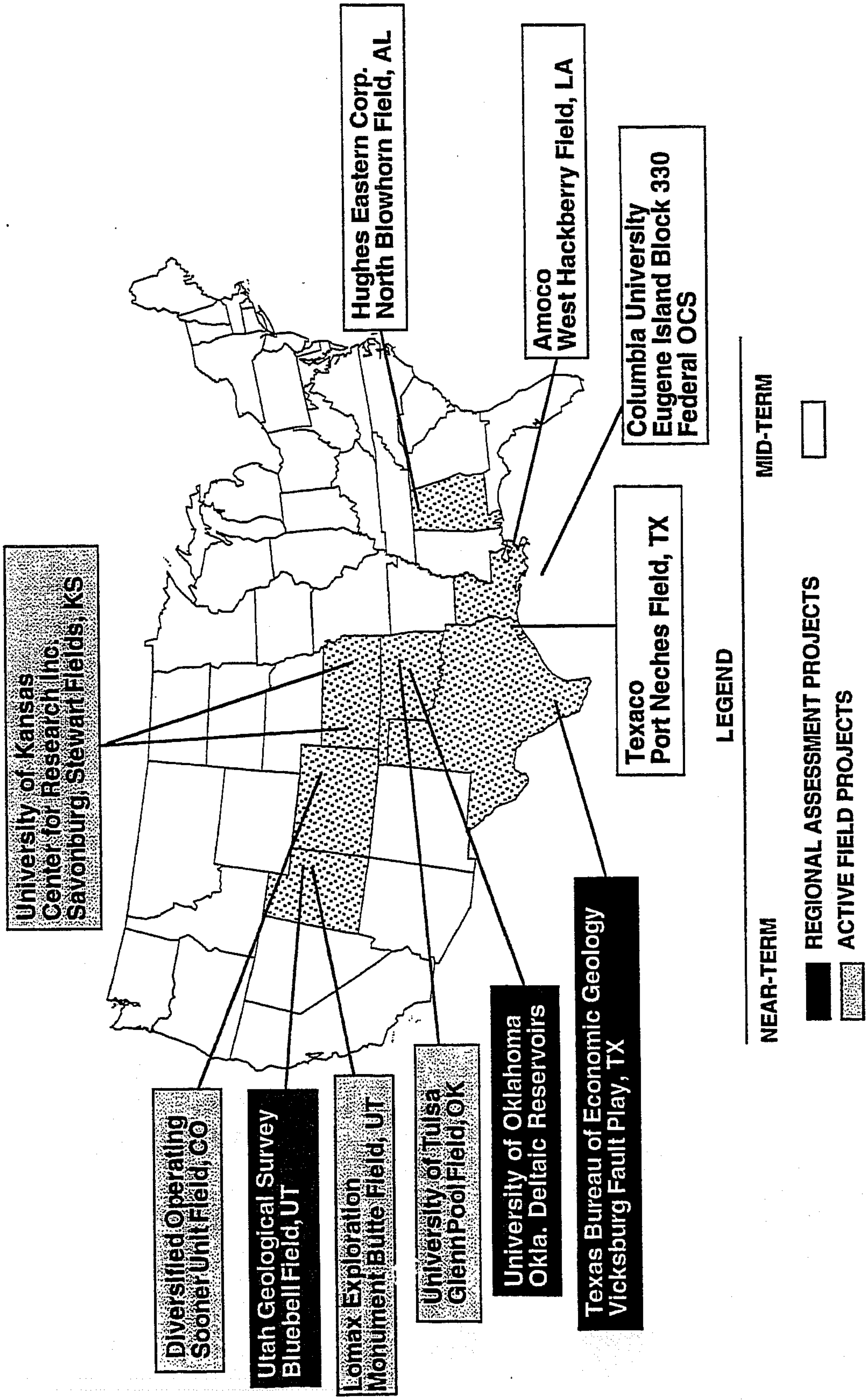


Figure 3 Class I Oil Recovery Projects

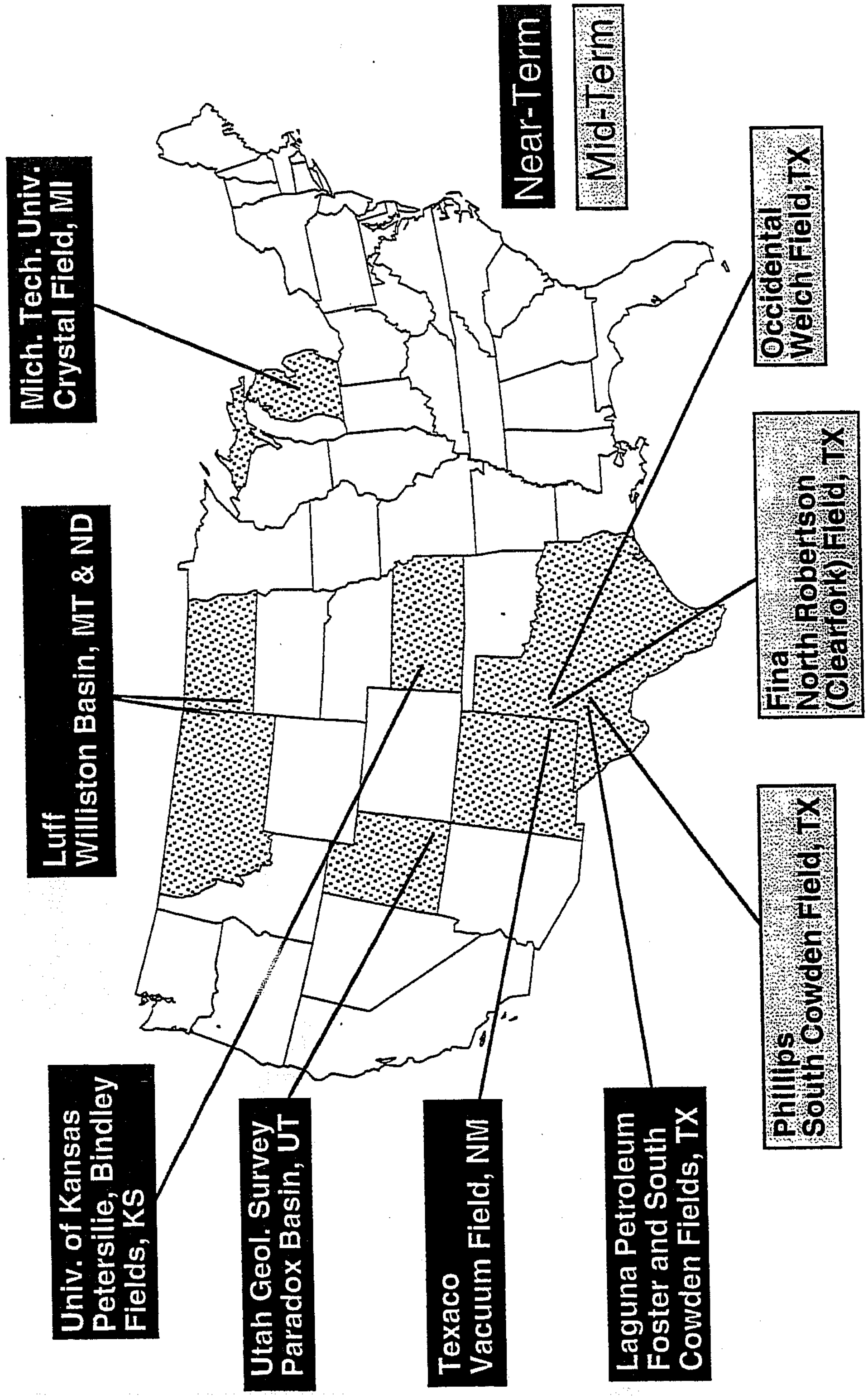


Figure 4 Class II Oil Recovery Projects

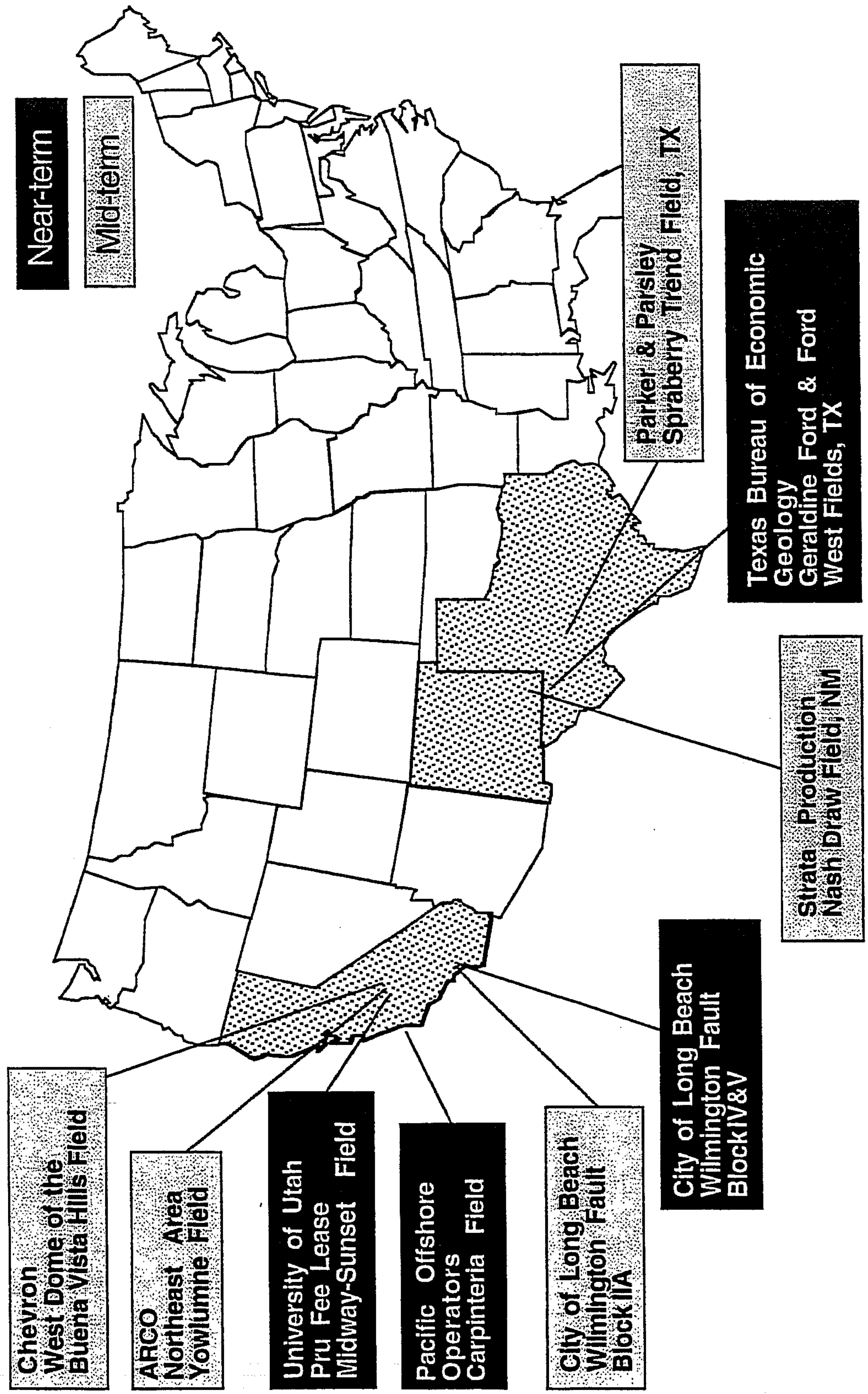
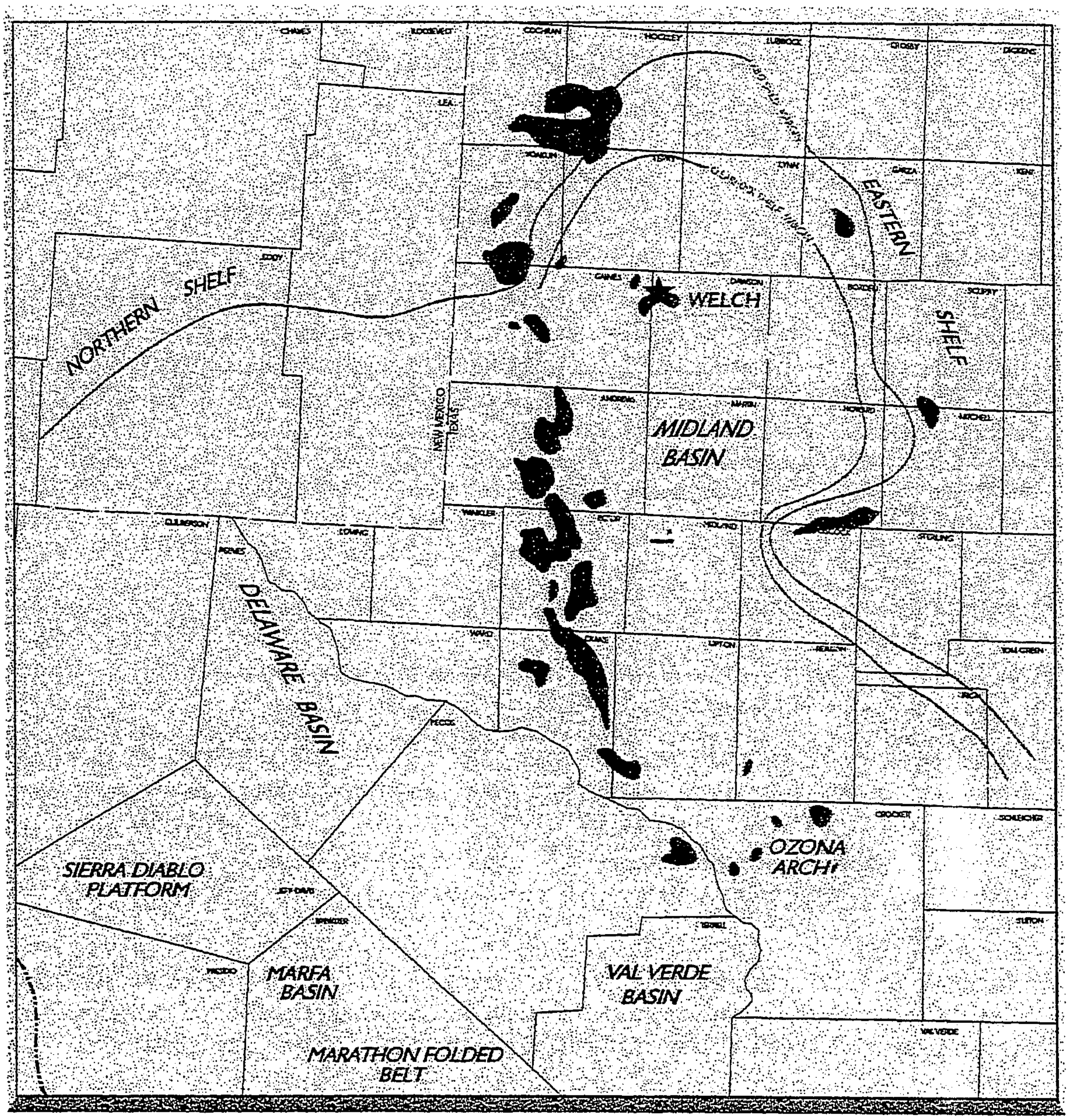


Figure 5 Class III Oil Recovery Projects

COMBINING FLOW THEORY AND MULTIPLE LOG READINGS TO IMPROVE PERMEABILITY CALCULATIONS

G. D. Hinterlong & A.R. Taylor
OXY USA Inc.
Midland, Texas

Location of Welch Project



Permian Paleogeography of the Permian Basin

Grayburg-San Andres Oil Fields with Cumulative Production21B Greater than 10 MMB

Shelf/Platform/Arch

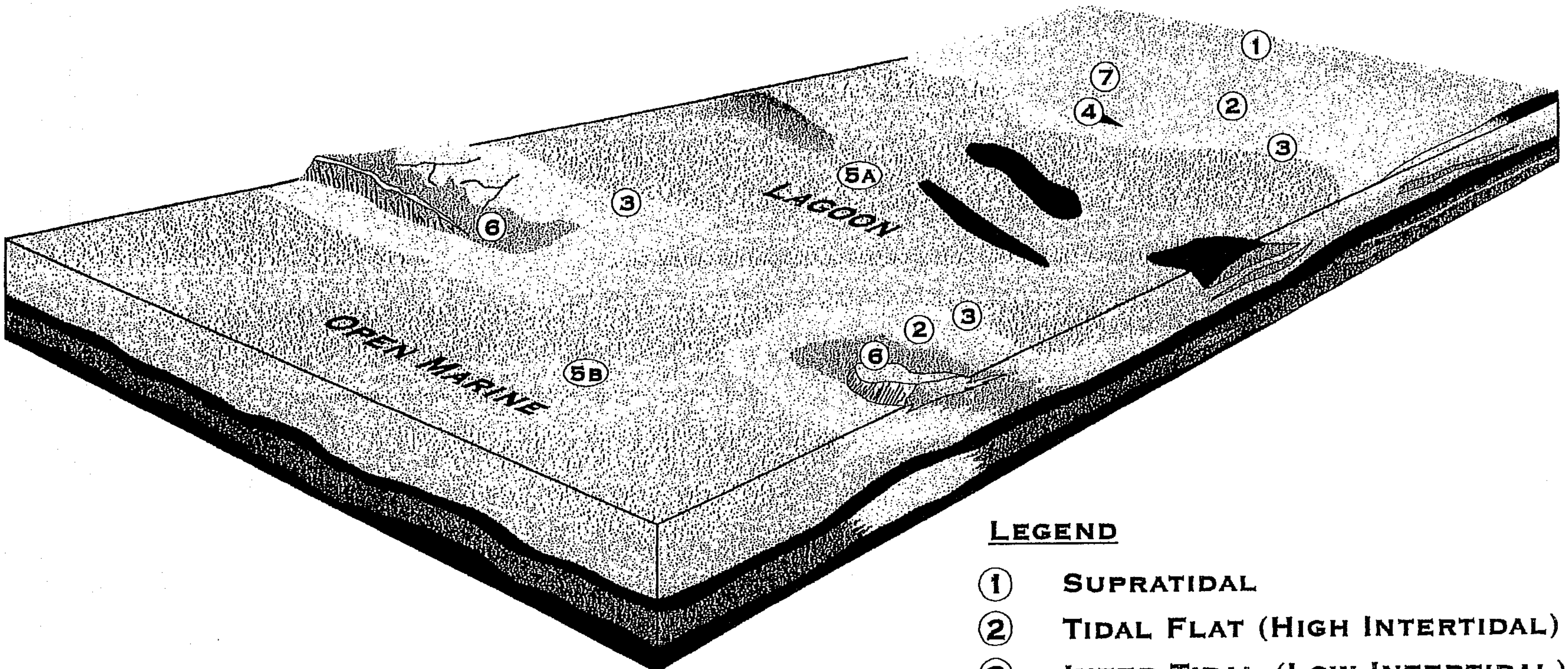
Basin

Stratigraphic Column

<table>
<tr><th>Age</th><th colspan="2">Geologic Epoch</th><th colspan="2">Delaware Basin</th><th colspan="2">Central Basin Platform</th><th>Midland Basin</th></tr>
<tr><td rowspan="15">P E R M I A N</td><td colspan="2" rowspan="4">Ochoan</td><td colspan="5">Dewey Lake</td></tr>
<tr><td colspan="5">Rustler</td></tr>
<tr><td colspan="5">Salado</td></tr>
<tr><td colspan="2">Castile</td><td colspan="3"></td></tr>
<tr><td rowspan="7">GUADALUPIAN</td><td rowspan="3">Late</td><td rowspan="3">Bell Canyon</td><td rowspan="3">Capitan Reef</td><td colspan="3">Tansill</td></tr>
<tr><td colspan="3">Yates</td></tr>
<tr><td colspan="3">Seven Rivers</td></tr>
<tr><td rowspan="3">Middle</td><td rowspan="2">Cherry Canyon</td><td rowspan="2">Goat Seep and Getaway</td><td colspan="3">Queen</td></tr>
<tr><td colspan="3">Grayburg</td></tr>
<tr><td colspan="2">Cherry Canyon Tongue</td><td rowspan="2">San Andres</td><td>Upper</td><td></td></tr>
<tr><td>Early</td><td colspan="2">Brushy Canyon</td><td>Lower</td><td>San Andres</td></tr>
<tr><td colspan="2" rowspan="4">Leonardian</td><td colspan="2" rowspan="4">Bone Spring</td><td colspan="2">Glorieta</td><td rowspan="2">Clear Fork</td></tr>
<tr><td colspan="2" rowspan="2">Clear Fork (Yeso)</td></tr>
<tr><td>Spraberry</td></tr>
<tr><td colspan="2">Tubb-Drinkard</td><td>Dean</td></tr>
</table>

ENG12

Welch Depositional Model



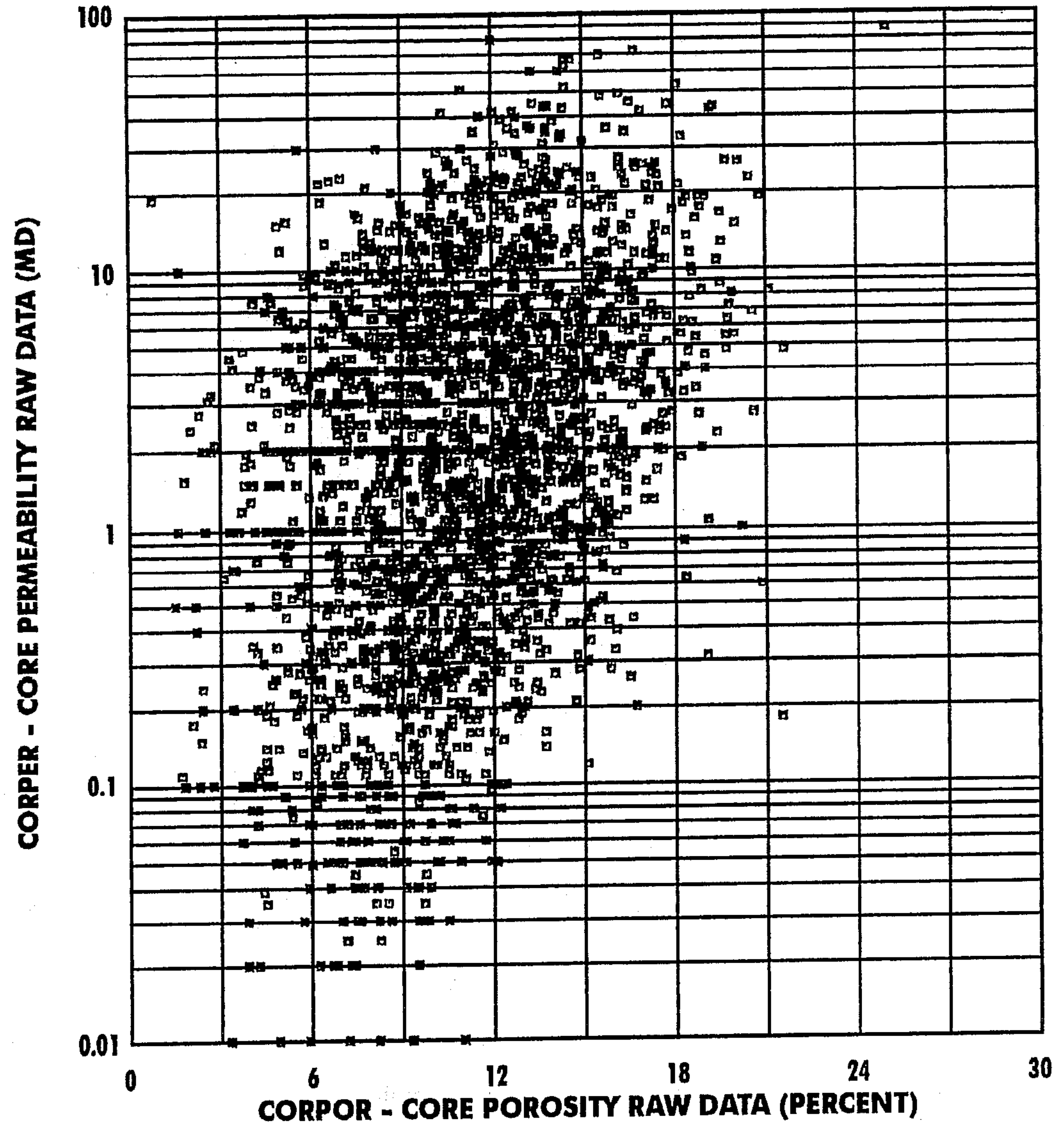
Legend

1. Supratidal
2. Tidal Flat (High Intertidal)
3. Inter Tidal (Low Intertidal)
4. Tidal Channel
5A. Subtidal Lagoon
5B. Subtidal Open marine
6. Grainstone Shoal
7. Tidal Pond

11/96 GH/JRR EXP91.CDR

DOE PROJECT AREA DAWSON COUNTY, TX

23 WELLS MAIN PAY



West Welch Unit
8 Layer Model

FACIES

Supratidal

Intertidal to Supratidal

Subtidal

Intertidal to Supratidal

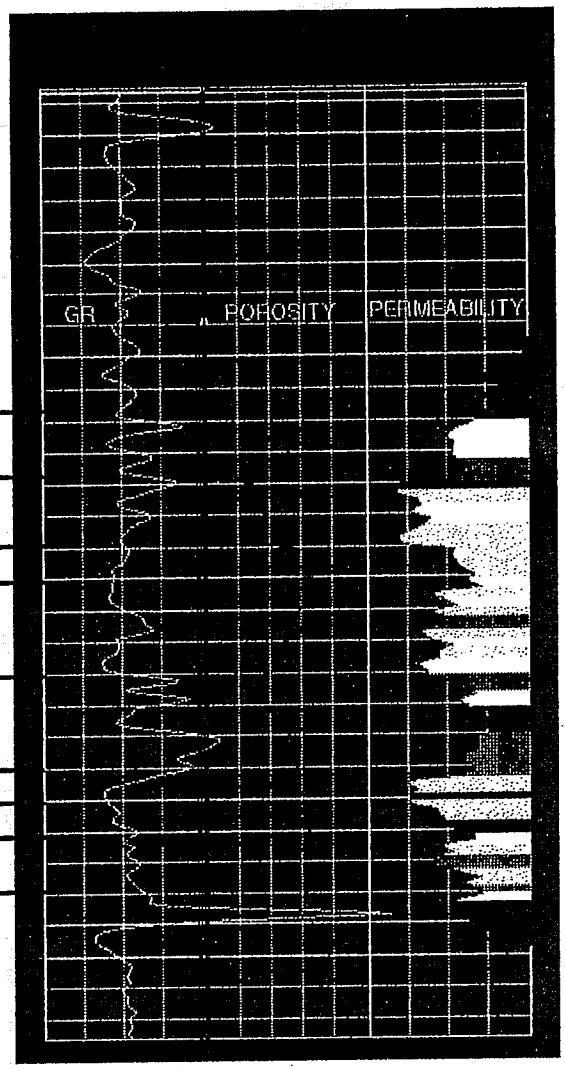
Subtidal

Supratidal

Subtidal

Intertidal to Supratidal

Subtidal



ROCK FABRIC

Packstones & Grainstones

with Leached Birdseye & Vug Porosity

with Grainmoldic Porosity

with Intergranular & Intercrystalline Porosity

with Intergranular Porosity

Wackestones & Mudstones

with Separate Vug Porosity

with Fine Intercrystalline Porosity

with Coarse Intercrystalline Porosity

Visual Analysis

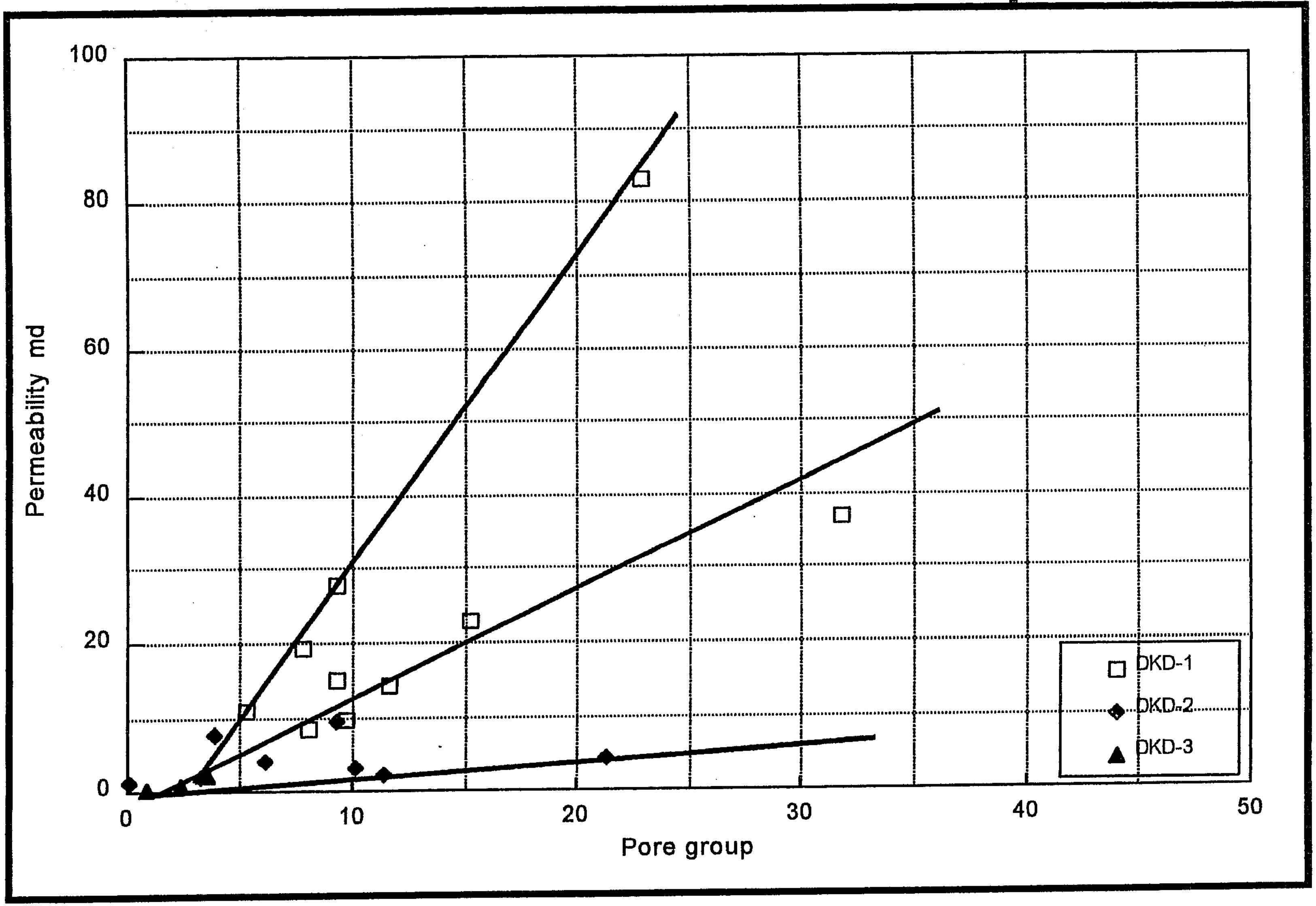
- Thin sections showed 8 major facies.
- These 8 facies showed 4 porosity permeability transforms.
- Image analysis resulted in 4 porosity permeability transforms.
- Log responses to the 4 transforms were not consistent.

Pore Radius Group Equations

$$k = \frac{\Phi * r^2}{4K_o\tau}$$

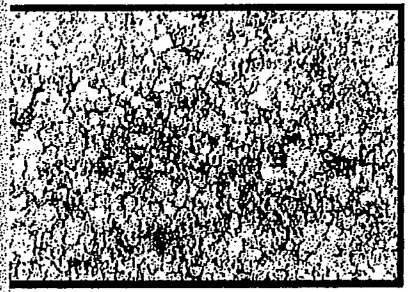
$$PRG = \frac{\Phi * r^2}{4}$$

Pore Radius Groups



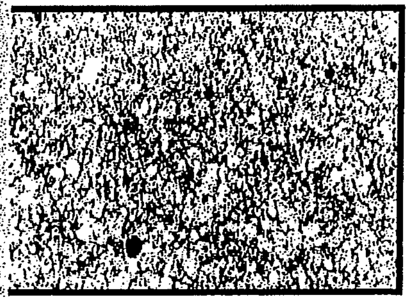
Pore Radius Group

Representative Thin Sections



Group 1

Large Crystal Size and Smooth Pores



Group 2

Smaller Crystal Size, Rougher Pores, and Grain Ghosts

Group 3

Perserved Grains very rough pore interiors

Tortuosity

$$\tau = \phi^{m-1}$$

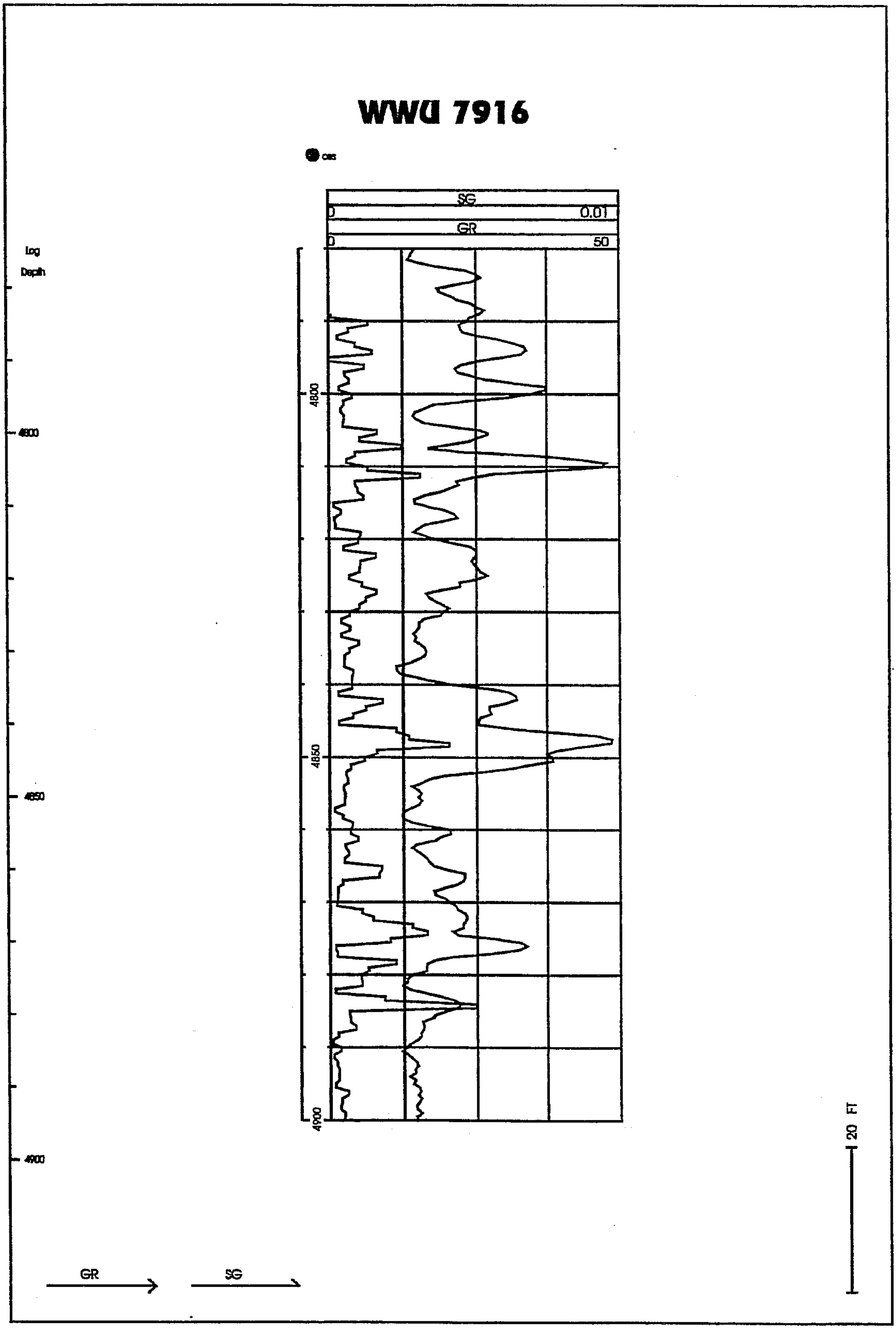
- τ = tortuosity
- m = Archie cementation exponent
- ϕ = porosity

Modified Carmen Kozeny

- **Surface Area Equation**

$$k = \frac{\Phi^3}{5 * S_s^2 * (1-\Phi)^2}$$

Comparison of Calculated Surface Area to Gamma Ray Log



Cementation Exponents

Nugent 1984

$$m_N = \frac{2 * \log(\Phi_s)}{\log(\Phi_t)}$$

Nugent Resistivity

$$m_{NR} = \frac{2 * \log(\Phi_r)}{\log(\Phi_e)}$$

Focke and Munn

$$m = 1.4 + .0857 * \Phi_t$$

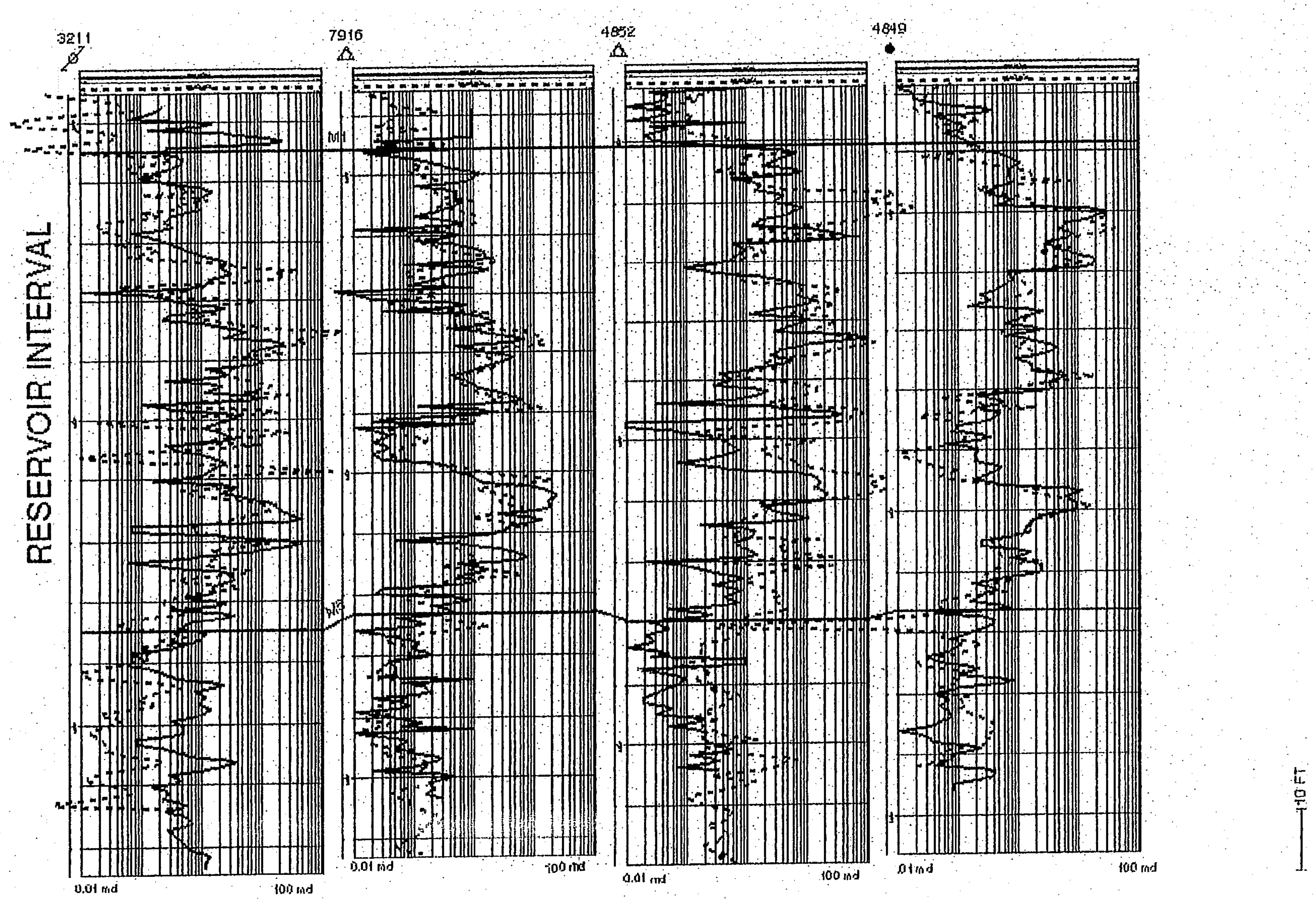
ENG124-16

Resistivity Derived Porosity Equation

$$\Phi = \sqrt[m]{\frac{Rxo}{Rmf}}$$

ENG123

Permeability from Nugent m



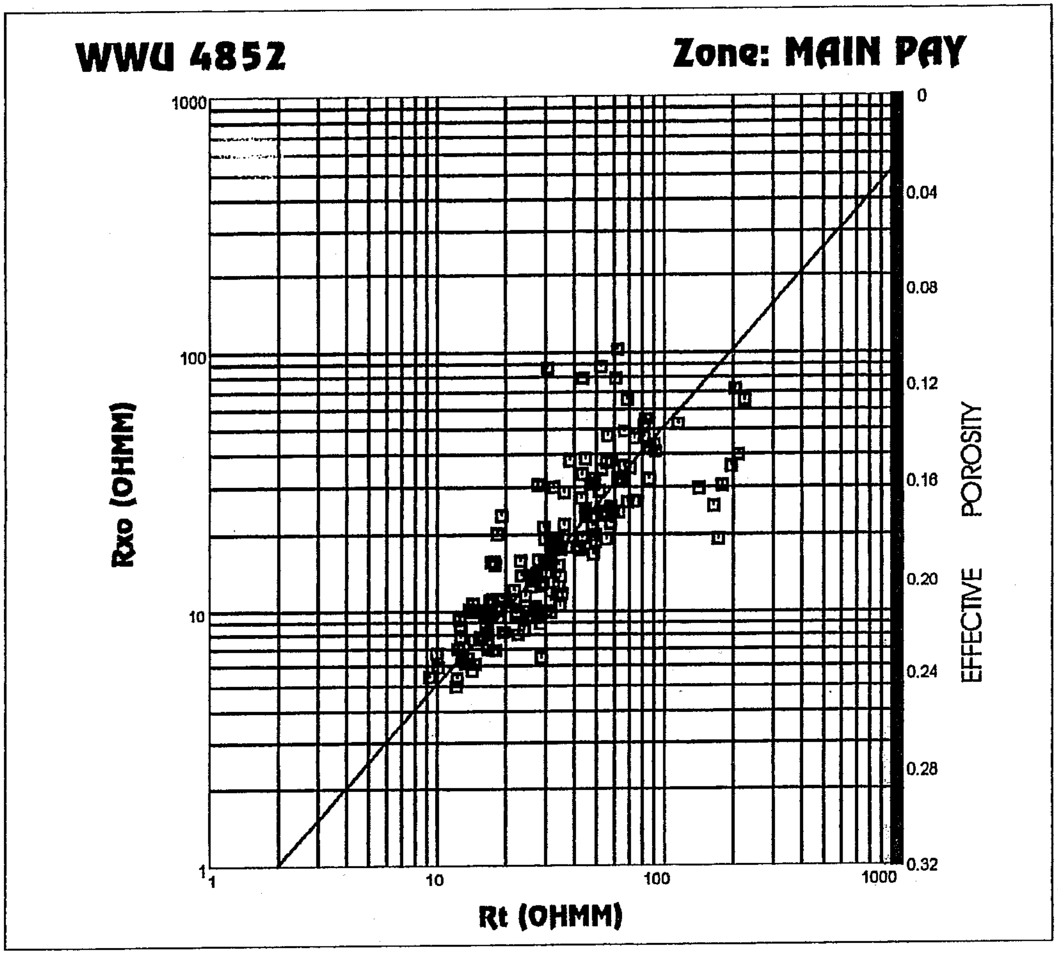
Modified Carmen Kozeny

$$k = \frac{100 * \Phi^3}{m_{NR} * GR_n^2 * (1 - \Phi)^2}$$

- Normalized GR (~0-1)
- Nugent Cementation Exponent
- Constant

ENG12

Log Rxo vs. Log RT



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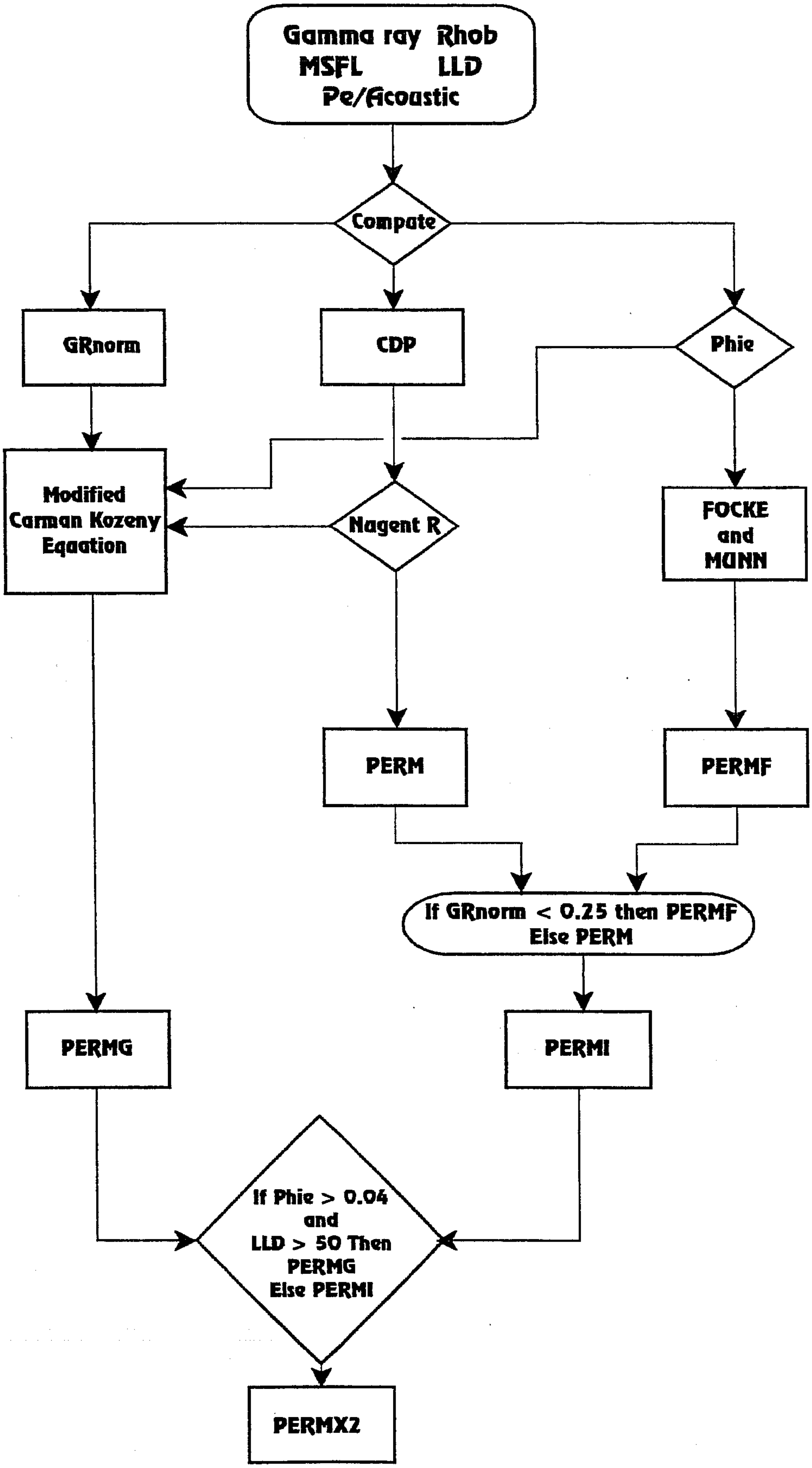
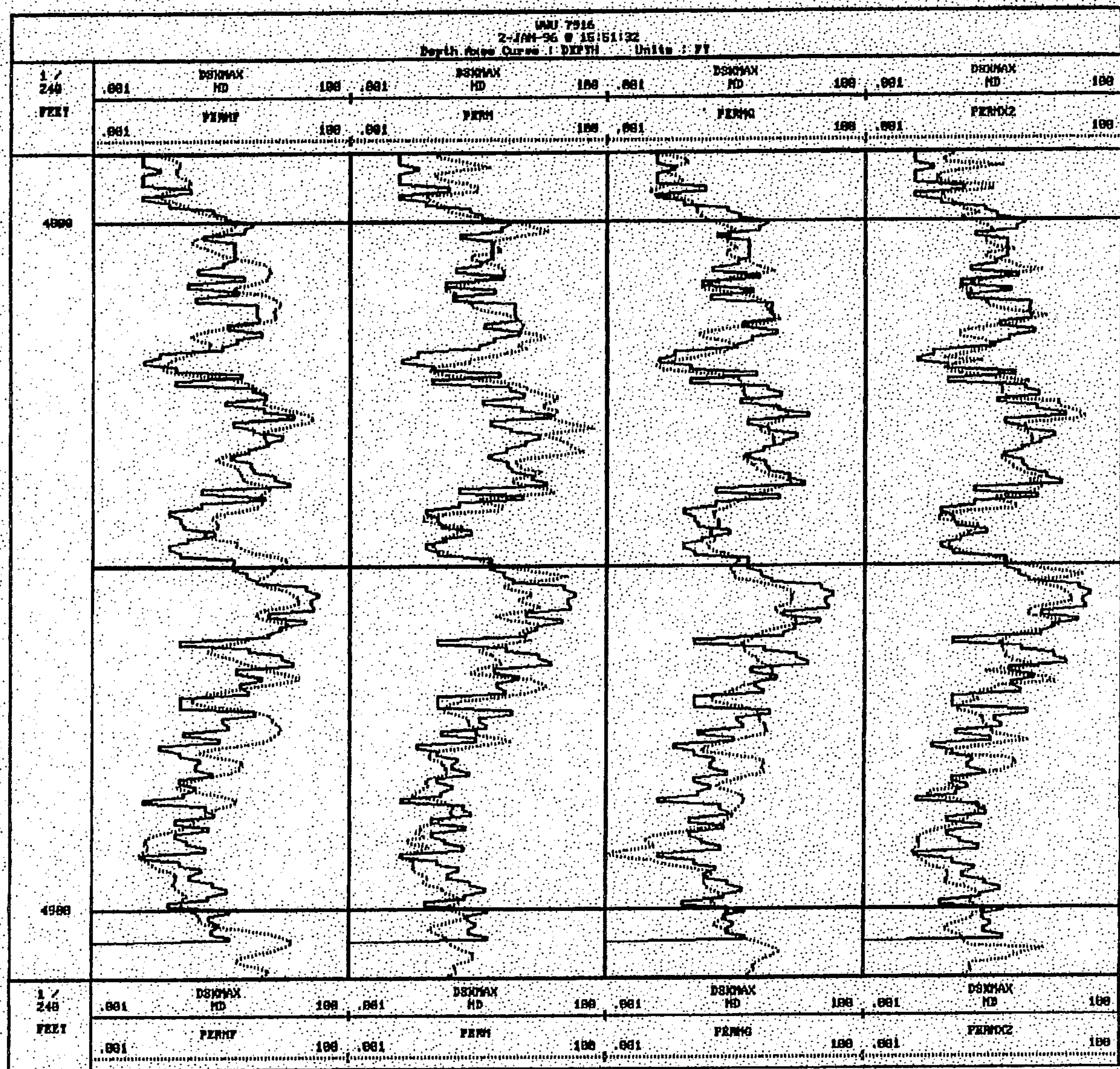
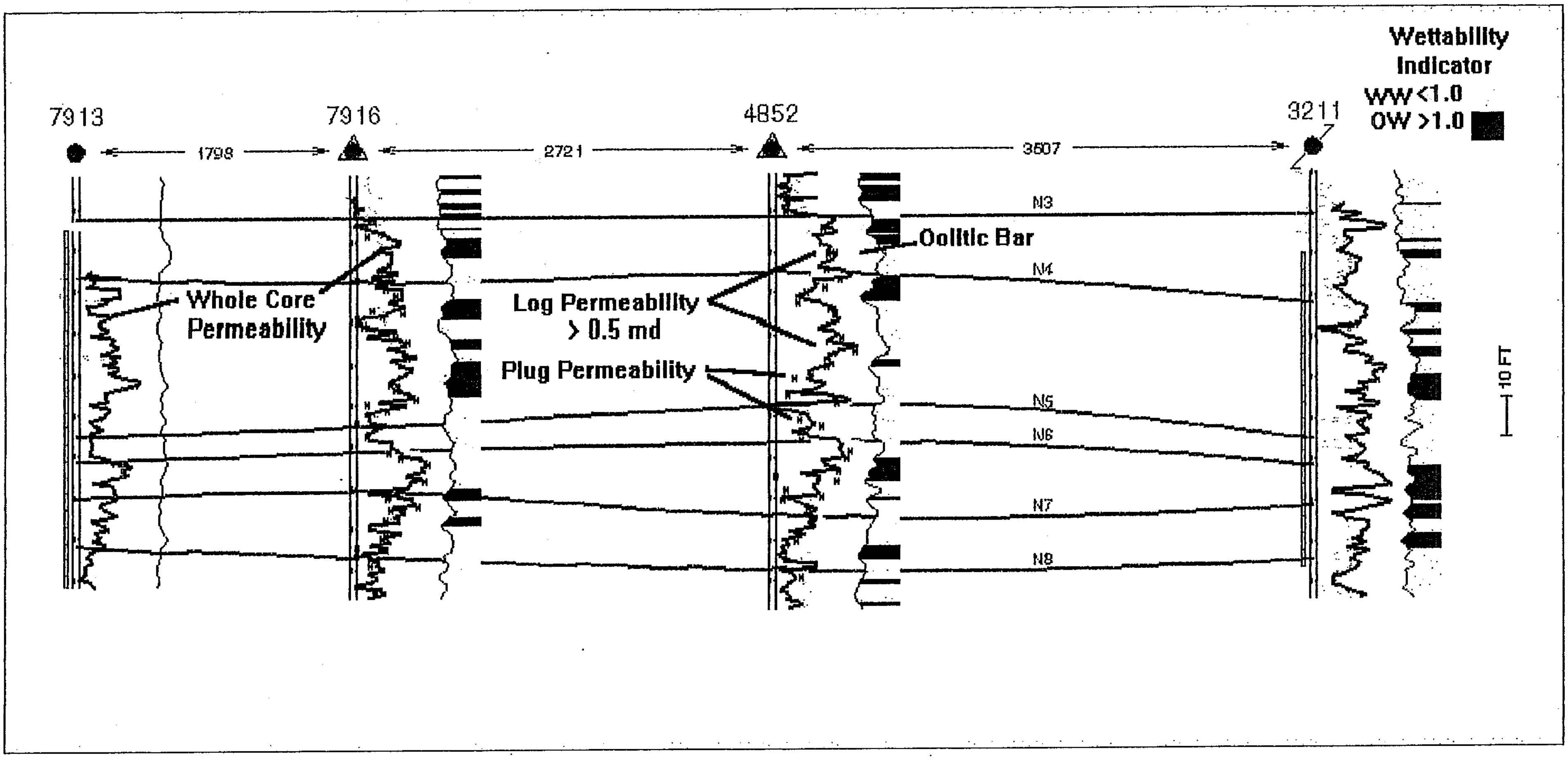
FLOW CHART


Gamma ray Rhob
MSFL LLD
Pe/Acoustic
Compate
GRnorm
CDP
Phie
Modified Carman Kozeny Eqation
Nagent R
FOCKE and MUNN
PERM
PERMF
If GRnorm < 0.25 then PERMF Else PERM
PERMG
PERMI
If Phie > 0.04 and LLD > 50 Then PERMG Else PERMI
PERMX2

Final Permeability Comparison



Wellbore Data



Conclusions

- Pores and pore throats control porosity permeability transforms.
- Wettability effects need to be accounted for in core to log transforms.
- A theoretical model provides a framework for integrating log responses.
- A foot by foot permeability determination can be made over the logged interval.

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CLASS II OIL PROGRAM (WEST WELCH) COOPERATIVE AGREEMENT DE-FC22-94BC14990

ENG1

Combining Flow Theory and Multiple Log Readings to Improve Permeability Calculations

G. D. Hinterlong and A.R.Taylor, OXY USA Inc., Midland TX

Acknowledgments

The Authors would like to thank OXY USA Inc. and the Department of Energy for their support and permission to publish the results of our investigations.

Abstract

The West Welch San Andres Unit is located in the northwest corner of Dawson County, Texas. Permian age dolomites produce from an average depth of 1463 m (4800 feet). A proposed CO_2 injection project required a detailed description of reservoir properties.

Rock typing, by visual description of core and thin section, yielded eight rock types present in the reservoir interval. Petrographic image analysis yielded a classification of the reservoir rock into four types. Correlating either scheme to log data met with limited success. Relative permeability data indicated water-wet and mixed wettability intervals.

Starting with a theoretical model, key variables such as pore geometry, pore surface area, and flow path length relates to log response. Laboratory and log data provide Carmen Kozeny equation factors resulting in a continuous permeability profile with rapid changes accounted for continuously. Changes in wettability determined from logs refine the analysis. The final computed curves guided the reservoir description process.

The process is limited to wells with sufficient data, and the generated values apply to the well bore area only and a knowledge of all rock types present is critical. The results are comparable to core data but is considerably less expensive than coring the same number of wells.

Introduction:

The results presented herein were derived from a partially funded DOE Class II project (DE-FC22-93BC14990). The scope of the project required a geologic description of the reservoir for numerical simulation to design and implement an economic CO_2 flood in a low permeability, heterogeneous reservoir. One of the objectives is to develop methodologies by which other operators can perform the descriptions in other fields.

The Welch Field is located in the northwest corner of Dawson County, Texas, on the northern shelf of the Midland Basin (Figure 1). The field produces from dolomite of the Permian age (Guadalupian) San Andres Formation at an average measured depth of 1463 m (4800 feet). The producing interval is approximately 122 m (400 feet) below the top of the formation. The reservoir section thins to the north toward the paleoshoreline and is overlain by impermeable evaporites and anhydritic dolomites. Permeability decreases to the east and west. The southern limits of the field are determined by down dip high water saturations. Current structure (Figure 2) reflects post-depositional movement of deeper fault blocks. A 3D seismic survey of the field confirms that these faults do not reach the San Andres interval.

The average porosity for the unit is 9.5%, with a geometric average permeability of 1 md. Within the project area the average porosity is 12 % and the average permeability is 2.2 md. As of December 1995, the West Welch Unit has produced 67 MMBO, 11 BCFG and 129 MMBW. Since water flood operations began in 1960, 254 MMBW have been injected. The West Welch Unit currently has 340 active producers and 207 active injection wells and covers over 12,000 surface acres. Current monthly production is 2,837 BO, 518 MCFG, and 22,896 BW. The unit wide average water cut is 89%. The DOE project area covers 564 acres in the south central portion of the West Welch Unit. This area alone has produced 7.7 MMBO. The project area currently has 38 producing wells, 23 injection wells, two observation wells, and one water supply well. Eleven of the wells within the project area have been cored.

Classification of rock types by visual description of core and thin section yielded eight rock types present in the reservoir interval. The relative permeability data indicated the reservoir had various wettabilities. Analysis of samples by petrographic image analysis yielded a classification of the reservoir into four classes. Comparison of both classification schemes to the log data met with limited success.

Starting with a theoretical model, key variables were ascertained, such as pore geometry, internal surface area of the pores, and the length of the flow path. By relating the primary response of the logs to the laboratory data, specific factors of the Carmen Kozeny equation can be derived through independent log measurements.

The result is a continuous permeability profile for the logged section with the rapid small scale changes accounted for in a continuous manner. Changes in the wettability are determined from the calibrated log response to refine the analysis. The final computed curve guides the layering process.

The process is limited to wells with sufficient curve data, and the generated data applies to the well bore area only. A knowledge of all rock types present provides the validation of the analysis. The results are comparable to core data but remain considerably less expensive than coring the same number of wells.

Background.

The standard approach is to identify the rock types present and establish the petrophysical character of each rock type to guide the building of the permeability profile. The initial reservoir description began with the classification of rock types present by core and thin section examination. The result was a classification scheme of eight different rock types. This data was constructed on the arrangement of the grains and pores; however, rock types could not be reliably predicted from the log response to permit the extrapolation to wells without cores.

Another approach was performed by a consulting firm whereby the reservoir was divided into three reservoir rock types and one non-reservoir type. The arrangement of the classification is based on the internal pore structure as determined by petrographic image analysis. Even with the reduction in rock types, the classification did not permit satisfactory prediction with log response.

Concurrent with this classification, relative permeability experiments were being conducted on core samples from the project area. The results of the experiments indicated the formation was of mixed wettability ranging from water-wet to intermediate oil-wet. The change in wettability would hamper the accurate prediction of rock type from well logs. In both instances, changes in rock wettability hindered the identification of the rock types by log response.

The prediction of permeability by porosity alone has been used extensively in reservoir description but has no basis in theory. The empirical correlation assumes that the interconnected pore space improves directly with the increase in total pore volume. The relationship has had successes in sandstone reservoirs but the more complex nature of the carbonate pore structure rarely fits this relationship. As a result, a single porosity value may have a permeability range covering several orders of magnitude. The real control of permeability lies in the pore throats between the pores. Larger pore throats can be measured directly with pore casts and SEM. Capillary pressure measurements will provide the pore volume connected by pore throats of a effective radius but does not measure the pore throats directly.

There is no log that measures permeability directly;however, there isalso no laboratory device that directly measures permeability. In the laboratory, measurements of other parameters are made on core samples and the Darcy equation is used to calculate the permeability of the sample. Earlier attempts at determining permeability from logs utilized standard log computations such as water saturation and clay volume. These values have uncertainties inherent with the computation by the assumptions used such as 'm', 'n', and connate water resistivity all used in an empirical relationship (Archie Equation).

The dominant factors controlling the permeability are the pore throat diameter and the number of pore throats connecting a pore. Recent work by Herrick and Kennedy has provided insight on the nature and controls of the resistivity tool response in formations (Herrick and Kennedy, 1993). Their work using finite difference modeling of pore systems illustrates the overwhelming effect of the size of the pore throat when compared to the contribution by the pore body.

Prior to logging, the drilling fluid flushes the moveable oil from the near well bore area. If the rock has a uniform pore system without dead end pore space, or high aspect ratio, the deep resistivity and the flushed zone resistivity should plot as a straight line on a log-log plot (Figure 3). Changes in the pore type and wettability will affect the shape of the line. The technique is in the log analysis literature using a technique called a Dew Plot (Asquith, 1995).

When the rock is water-wet, the changes in resistivity to residual oil will be greater than when the rock is oil-wet. The oil-wet rocks will have smaller effective pore throats to the flow of current. This is caused by the resistive oil lining the pore and pore throats, thereby reducing the diameter of conductive fluid phase in the pore system.

Theoretical Relationship.

The Carman Kozeny equation (CKE) (1927,1929) characterizes the permeability as a function of the pore volume, the length of the flow path (τ), and the internal surface area (K_o, Kozeny Factor). The model represents a bundle of capillary tubes. Once these factors are determined, the permeability of the rock can be calculated. Because of the expense and difficulty in measuring these factors,

$$k=\frac{\phi^3}{\tau K_0(1-\phi)^2} \quad \text{.........................(1)}$$

average values are normally assumed. In this paper, log responses have been equated to each of the factors. Because several independent measurements are used, continuous variations in the pore structure are accounted for in the computed permeability. The Kozeny Factor (K_o) is determined from the total gamma ray log response. The Tau (τ) is determined from the pad resistivity tool (Rxo), and the porosity is determined from the lithology-corrected density log. The comparison of the deep reading resistivity tool and the porosity yields information as to the formation wettability. The selection and use of these particular input curves has been documented in several instances in the literature (Mohaghegh, Ameri, and Arefi, 1996; Yao and Holditch, 1993). The critical aspect is the inclusion of the resistivity measurements into the calculations.

The pore geometry description requires accounting for the multiple aspects of pore size, ratio of pore body to pore throat diameters, roughness of the pore wall, and the degree of interconnection between the pores. In the CK equation, the Kozeny Factor K_o acts as a friction term in the equation and is related to the internal surface area of the pores and the pore body to pore throat diameters. Special laboratory measurements can be made to approximate this area. Approximations have also been made for pore surface area based on the mineralogy of the pore system. The first method is expensive and difficult to perform. The second method requires that these minerals actually form the lining of the pores.

For this project, a means had to be identified that would provide information as to grain size and the associated roughness of the pore walls. Mineralogically, the reservoir is composed of

$$k(Darcys)=\frac{\phi^3}{5Sg^2(1-\phi)^2}\text{.............................}(2)$$

dolomite and anhydrite (approximately 96%) with the rest being silica in the form of quartz silt and chert, and clays (illite and kaolinite). Application of mineral-specific surface area would be ineffective due to the high degree of crystal or grain size distribution within the reservoir (<10 microns to > 1000 microns). From SEM examination, the clays present in the formation do not reside within the pore system and, as such, do little to affect the permeability or water saturation. Monicard (1980) found acceptable values for surface area could be generated using porosity and permeability values from analyzed core samples, transformed using a modified CK equation. The equation (2) proposed by Monicard was used to compute the internal surface area. This equation was applied to the core data obtained from the model area. The total gamma ray curve was found to have comparable deflections as the internal surface area curve computed from core analyses (Figure 4). Spectral gamma ray logs were not available to identify the cause of the radiation; however, the finer crystal sizes equated to intervals of higher gamma radiation. It is postulated that the finer crystals contain more impurities retained in the rapid growth of the crystals.

The correlation was improved by normalizing the gamma ray response to the maximum and minimum deflections within the reservoir interval using equation 3. By restricting the selection of

$$GR_{NORM} = \frac{GR - GR_{MIN}}{GR_{MAX} - GR_{MIN}} \ldots\ldots(3)$$

minimum and maximum values to within the reservoir interval, the incorporation of diagenetic processes outside the reservoir interval was avoided in the normalization process. The maximum and minimum values were surprisingly similar even though six different logging companies were used during the period of 1985 to 1994 when the control wells were logged. Maximum values were rounded up to the next highest whole number and the minimum values were likewise rounded down. The normalized value is to be used in the denominator and as such cannot be zero.

The other factors of tortuosity (τ) and effective pore throat diameter are parameters in the determination of permeability. The pore throats act as a choke of the system restricting the flow between pores. The tortuosity is the ratio of the total length of the flow path compared to the actual distance to reach the pressure sink (producing well). The flow of electric current has been equated to fluid flow since the early days of reservoir simulation when early simulators were actually large circuit boards. In non-conductive rocks the flow path of the current coincides with the flow path of the fluid. The resistance to flow is related to the length of the flow path, therefore logging tools measuring electrical properties of the formation should provide details of the fluid flow characteristics if interpreted properly.

The recent work by Herrick and Kennedy (1993) has shown that the effective diameter of the pore throat has a controlling effect on the electrical properties of the rocks as well. The result is that the resistance to current flow is the combination of the interconnected pore throats diameters and the length of the conductive fluid path.

This is not the first time that attempts have been made to determine Tau from resistivity measurements. Wyllie and Rose (1950), Cornell and Katz (1953) and Winsauer et. al (1952) related the porosity and formation resistivity factor (Ro/Rw) to Tau. Their efforts are summarized in Salem (1993). The bulk of the work done by these investigators was performed on sandstones and water-wet systems. Electrical logging tools of this period did not have the resolution of modern tools which may have attributed to the lack of attention to this work.

Although the information is contained within the resistivity measurements, developing an accurate interpretation of the values has been elusive. Nugent (1984) had developed a relationship

$$m=\frac{2\ Log(\phi_{Acoustic})}{Log(\phi_{Total})}\text{......}\textit{Nugent Equation}$$

to generate the tortuosity of a formation from the comparison of the acoustic porosity to the total porosity. The premise is the acoustic porosity represents the volume of interconnected porosity. When compared to the total porosity of the system, the Nugent Equation provides an estimation of the length of the flow path. The assumption is that the acoustic porosity is the actual interconnected porosity. Fractures and oversized pores are not readily detected by acoustic logging and may mislead the interpretation.

A porosity type calculation can be made from the resistivity measurements if the formation water resistivity and the cementation exponent from the Archie relation are known. During this study

$$\phi_R=m\sqrt{\frac{Rmf}{Rxo}}\text{..........(4)}$$

an assumed value of 2 was used for the 'm' in Equation 4. The calculated porosity value represents the volume of interconnected conductive fluid within the measurement area. The presence of hydrocarbons is not included in the porosity determination because they do not conduct electricity. By substituting the conductivity-derived porosity into Nugent's Equation for 'm', a ratio of the flow path to the total porosity is generated. Smaller values of the resistivity porosity indicate that there is a shorter flow path for the current to flow through. The result is that the higher values output from this equation (Nugent R) are indicative of higher permeabilities. A fair approximation of the permeability could be generated simply by rescaling the Nugent R values to the logarithm of the core permeability (Figure 5). In the West Welch reservoir, the Nugent R was rescaled from 1.5 to 3.5 to the -2 to 2 scale of the logarithm of permeability.

What is also significant is the distribution of the fluids within the pore system. In water-wet systems the conductive fluid is in contact with the rock. Capillary forces in smaller pore throats create oil droplet snapoff, trapping oil in the pore body while the water remains in a continuous phase through the system. Oil wet rocks reverse the distribution of the fluids with the oil now in contact with the pore wall. The conducting fluid will have a shorter path through the pore body, but the effective pore throat diameter is reduced. To compensate for the differences in log response, the wettability of the rock must be determined prior to the evaluation of the log-derived permeability.

Laboratory data verified the wettability nature of the rocks. Wettability was gleaned from the relative permeability experiments. By cross-plotting various data with the respective samples, the combination of the resistivity curve and the porosity curve illustrates the intervals of a change in wettability. In water-wet intervals, the pore volume decreases the resistivity increases; but in the mixed wettability samples, there was higher resistivity than samples of equal porosity in water wet samples. The comparison of the deep resistivity and the Rxo readings also displayed a distinct scatter from the water-wet relationship.

Results of Data.

Factors for the CK equation can now be determined on a sample basis equal to that of the log data (in this instance one half foot increments). When substituted into the equation, the CK equation recorded the closest to the mixed wettability and high aspect ratio pore systems. Other intervals did

$$k = \frac{100\ \phi^3}{(GR_{NORM})^2\ (NugentR)\ (1-\phi)^2}$$

not respond as well. Upon further examination these intervals were composed of smoother pores and more strongly water-wet pores. As described before, a rescale of the Nugent R curve fit most of the intervals which the CK equation did not match as well. There were also intervals that did not match well with either method. This third rock type was composed of what is commonly referred to as sucrosic dolomite, composed of large smooth crystals of dolomite. These intervals responded well to a single porosity- permeability transform. These intervals were identified by having a normalized gamma ray response of less than 0.25 (< 25% of the deflection range).

The combination of rock properties by log character and use of the transforms for the specific rock types enabled the calculation of a continuous permeability profile for the reservoir interval. This profile correlated well with measurements of whole core values (Figure 6). The additional advantage is that the rapid changes not reported in the core analyses become apparent in the log-generated profile. Unless specifically arranged, routine core analysis does have a sampling bias. The bias is cause by the laboratory personnel selecting samples from the core that appear to have a reasonable chance of yielding good data. Thin shales or anhydrite beds will often not be sampled. These omissions become significant when developing a reservoir model for simulation. Many thin shales have lateral continuity between wells and are vertical flow barriers.

The identified lower-permeability intervals were used to help define the layers within the reservoir. Because the log response is allowing for calculation of a sample-by-sample basis, lumping of petrophysical characteristics by zone is avoided so that deviation errors can be avoided or minimized.

Limiting Factors.

As with any reservoir description methodology, the limiting factors should be abundantly clear before applying the process. Even as detailed as the permeability profile is, it directly applies only to the near well bore area. Because logs record values from rock volumes different from those of core analysis, an exact match of the two profiles would only be expected in a uniform homogeneous reservoir. The match between the two profiles is as close as the comparison of plug core analysis to whole core analysis (Figure 7).

The use of multiple log curves does improve the computed permeabilities, but the procedure is limited to wells with sufficient log data: total gamma ray, deep resistivity, flushed zone resistivity, and bulk density (with a photoelectric and/or acoustic curve for lithology correction).

The final limiting factor is the knowledge of the rock types present; therefore, some core data is required. The larger the sample population, the greater the accuracy of the prediction. From the four control wells examined, only one interval in one well failed to respond to the process. This interval was composed of a rock type not observed in the other three wells. Work is in progress to identify this rock type for future work.

Potential.

The potential of this process is that reliable permeability values can be generated from less expensive common log data for improved reservoir characterization. Although some core is required to calibrate the log response, less arbitrary adjustments and assumptions are needed to compute values. The results can be more representative of reservoir permeability than core values due to a larger volume of the reservoir analyzed.

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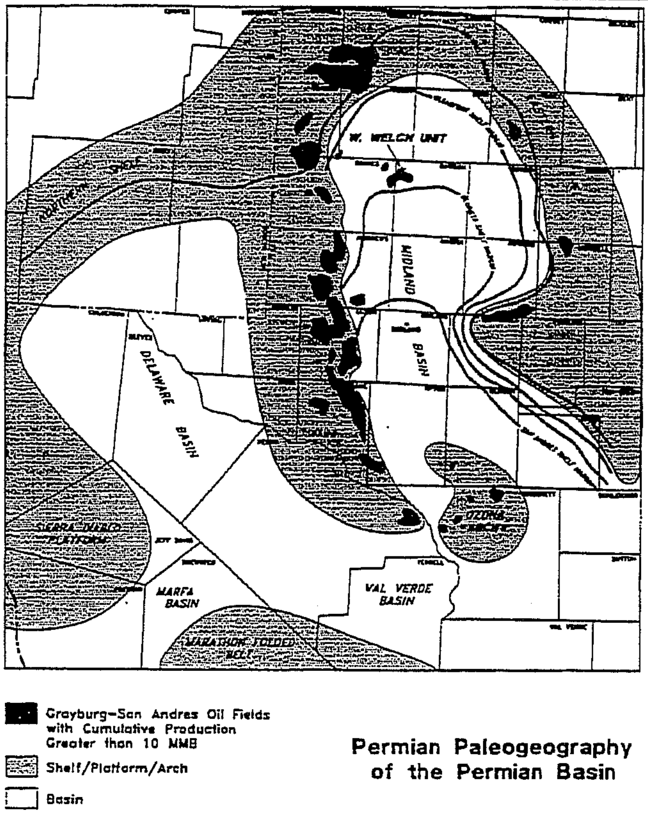

Figure 1 Paleogeographic map of the Permian Basin of West Texas and New Mexico showing the relation of the major features during Permian time and the location of the Welch Field. Locations of major petroleum reservoirs of the same formation are also shown.

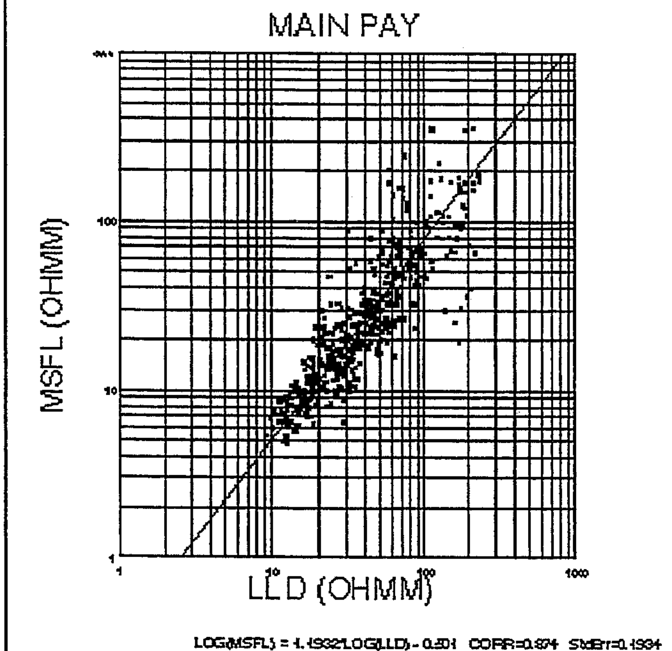

Figure 3 Cross plot of the deep reading resistivity log (Rt) versus the flushed zone reading resistivity log (Rxo) on logarithmic axes. The bulk of the data exhibits a linear relationship; however, in the range of 50 ohms, the data begins to disperse. The dispersion is caused by the change in wettability of the reservoir.

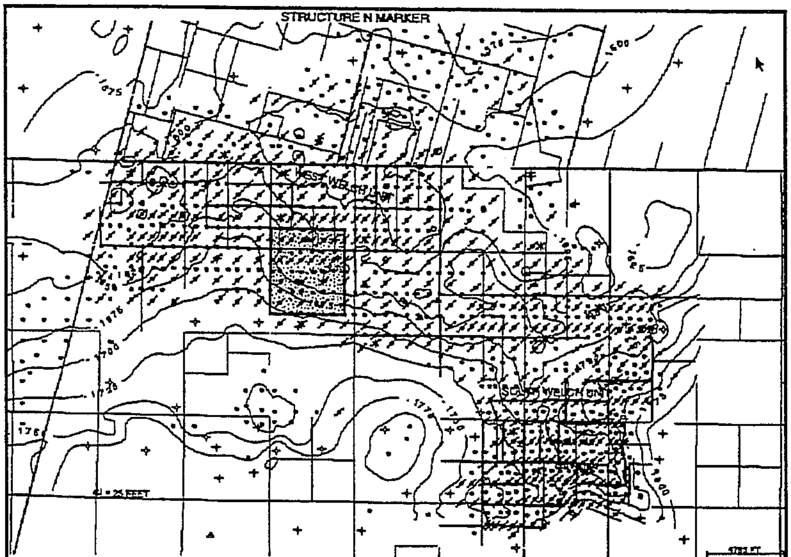

Figure 2 Structural contour map of the 'N' marker, a local mapping horizon approximately 18.3 meters (60 feet) above the top of the Welch reservoir interval. The structure gently dips to the south establishing the trap against the loss of permeability to the north. The project area is the 540 acre area (stippled) in the south central portion of the West Welch Unit.

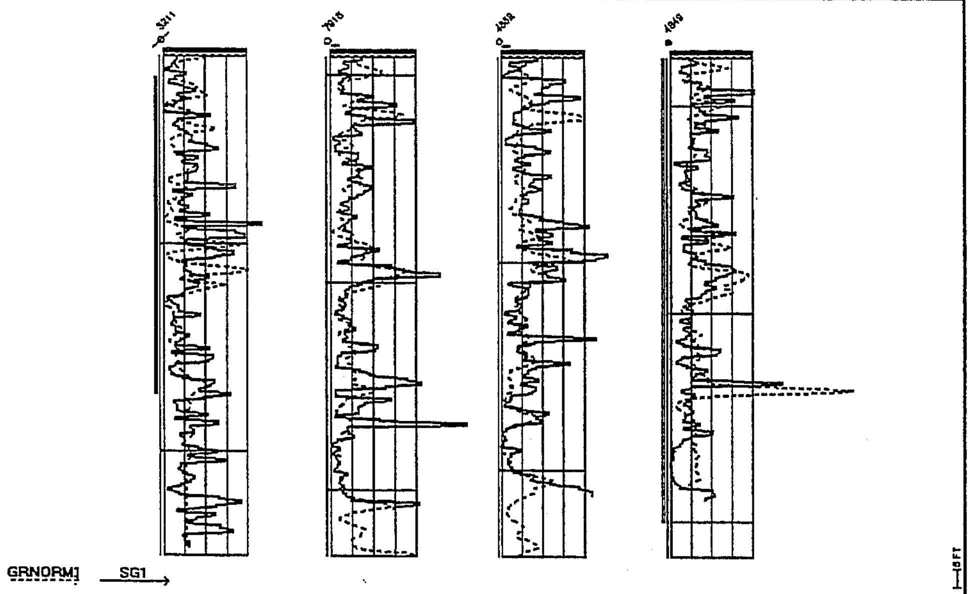

Figure 4. Comparison of the total gamma ray and the specific surface area computed from core data. The core data has been depth shifted to the open hole log data. Scales for both the surface area and the gamma ray are linear.

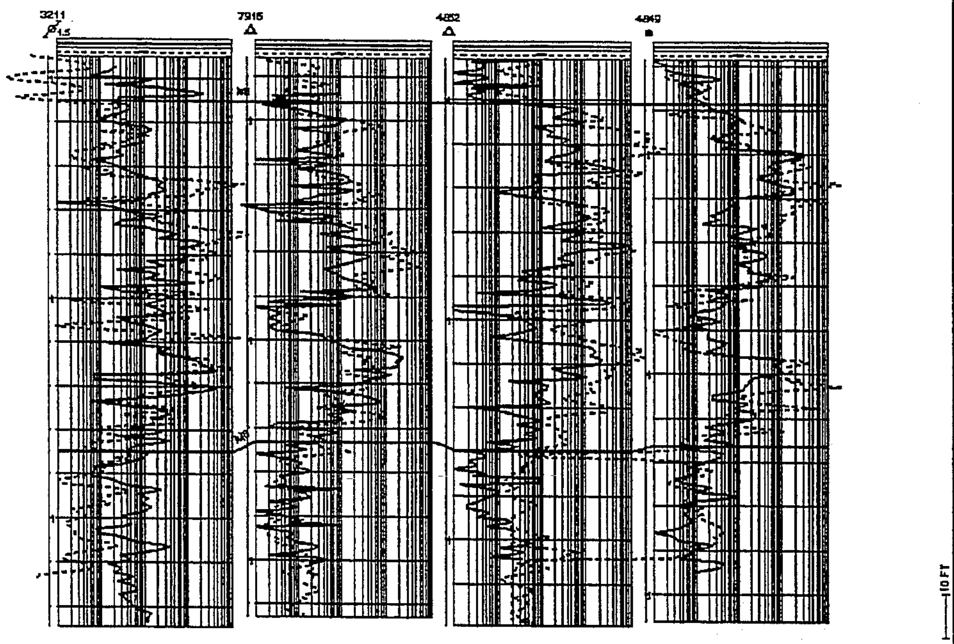

Figure 5. Comparison of the Nugent R (dashed)curve to the depth shifted whole core air permeability(solid curve). The permeability is scaled logarithmically from 0.01 to 100 md. and the Nugent R is scaled from 1.5 to 3.5 linearly.

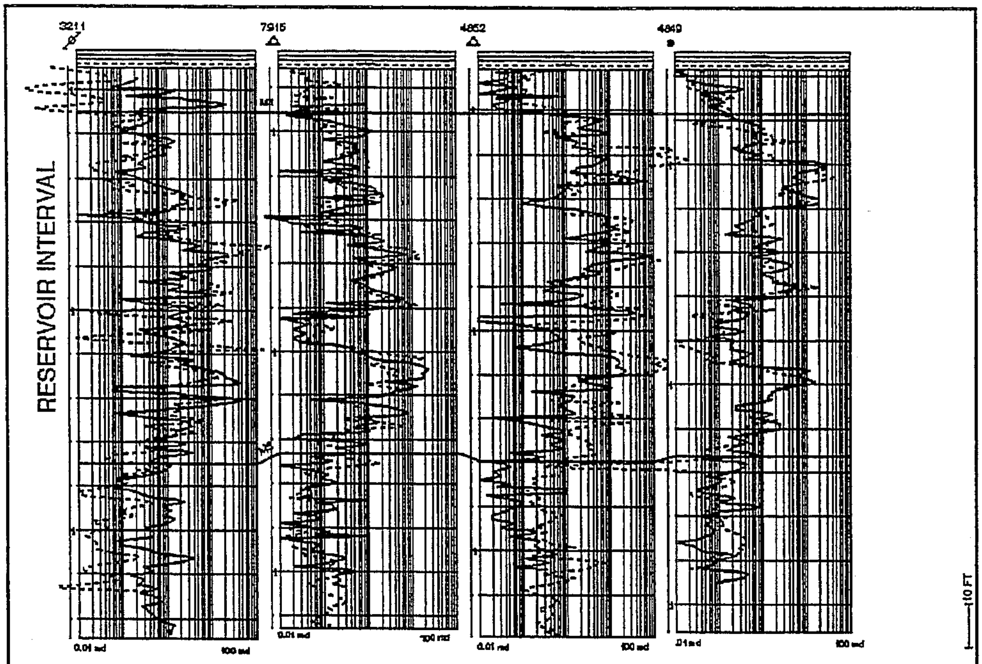

Figure 6. Comparison of final computed permeability curves(dashed) and the depth shifted whole core permeability(solid curve). Both curves are using identical scales, 0.01 to 100 md. displayed logarithmically.

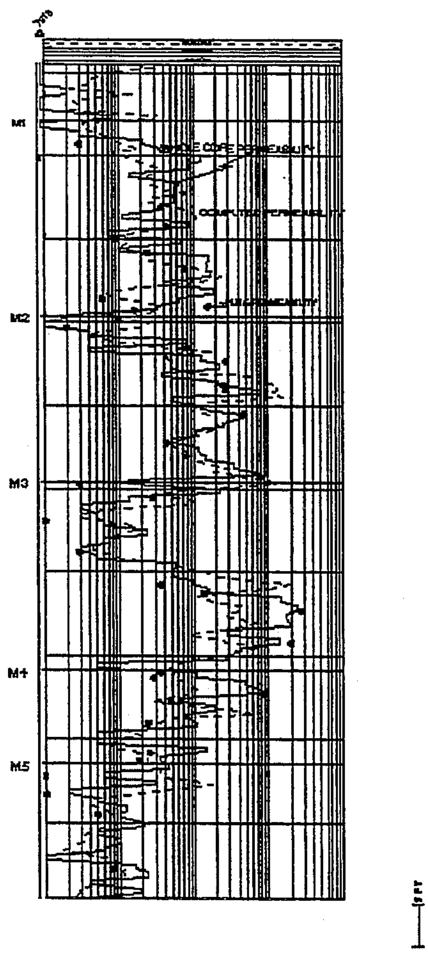

Figure 7. Comparison of whole core permeability (solid curve), plug permeability (dots), and computed permeability (dashed line) in the same well bore. The scales are the same for all three permeabilities. The amount of divergence between the computed and whole core permeability is comparable to the difference between the whole core and the plug analyses. In these carbonate reservoirs, the sample size effects the final permeability measurement.

An Integrated Geologic and Engineering Reservoir Characterization of the North Robertson (Clear Fork) Unit, Gaines County, Texas

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ABSTRACT

An integrated geological/petrophysical and reservoir engineering study has been performed for a large, mature waterflood project (>250 wells, ~80% water cut) at the North Robertson (Clear Fork) Unit, Gaines County, Texas. The primary goal of the study was to develop an integrated reservoir description for "targeted" (economic) 10-acre (4-hectare) infill drilling and future recovery operations in a low permeability (dolomite) carbonate reservoir. Integration of the results from geological/petrophysical studies and reservoir performance analyses provided a rapid and effective method for developing a comprehensive reservoir description.

This reservoir description can be used for reservoir flow simulation, performance prediction, infill targeting, waterflood management, and for optimizing well developments (patterns, completions, and stimulations). The following analyses were performed as part of this study:

- Geological/petrophysical analyses: (core and well log data)
  - "Rock typing" based on qualitative and quantitative visualization of pore-scale features.
  - Reservoir layering based on "rock typing" and hydraulic flow units.
  - Development of a "core-log" model to estimate permeability using porosity and other properties derived from well logs. The core-log model is based on "rock types."
- Engineering analyses: (production and injection history, well tests)
  - Material balance decline type curve analyses performed to estimate total reservoir volume, formation flow characteristics (flow capacity, skin factor, and fracture half-length), and indications of well/boundary interference.
  - Estimated ultimate recovery analyses yield movable oil (or injectable water) volumes, as well as indications of well and boundary interference.
  - Well tests provide estimates of flow capacity, indications of formation damage or stimulation, and estimates of drainage (or injection) volume pressures.

Maps of historical production characteristics (contacted oil-in-place, estimated ultimate recovery, and reservoir pressure) have been compared to maps generated from the geologic studies (rock type, permeability-thickness, hydrocarbon pore volume) to identify the areas of the unit to be targeted for infill drilling. Our results indicate that a close relationship exists between the rock type distribution and permeability calculated using porosity and other properties derived from well logs. The core-log model is based on "rock types."

The reservoir performance data also suggest that this reservoir depletes and recharges almost exclusively according to the rock type distribution. This integration of "rock" data and the reservoir performance attributes uses existing data and can eliminate the need for "evaluation" wells, as well as avoiding the loss of production that occurs when wells are shut-in for testing purposes.

In short, a comprehensive analysis, interpretation, and prediction of well and field performance can be completed quickly, at a minimal cost, and this analysis can be used to directly improve our understanding of reservoir structure and performance behavior in complex formations.

INTRODUCTION

This study was funded in part by the U.S. Department of Energy as part of the Class II Oil Program for improving development and exploitation of shallow-shelf carbonate reservoirs. According to the DOE, shallow-shelf carbonate (SSC) reservoirs in the USA originally contained >68 billion bbls of oil (10.81×10^9 m^3)--or about one-seventh of all the oil discovered in the Lower 48 States. Recovery efficiency in such reservoirs is low, as only 20 billion bbls of oil have been pro-

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duced, and current technology may only yield an additional 4 billion bbls (Pande, 1995).

The typical low recovery efficiency in SSC reservoirs is not restricted to the USA--it is a worldwide phenomenon. SSC reservoirs such as the North Robertson (Clear Fork) Unit (NRU) share a number of common characteristics (Pande, 1995), including:

- A high degree of areal and vertical heterogeneity, relatively low porosity and low permeability,
- Reservoir compartmentalization, resulting in poor vertical and lateral continuity of the reservoir flow units and poor sweep efficiency,
- Poor balancing of injection and production rates, and early water breakthrough in certain areas of the reservoir. This indicates poor pressure and fluid communication and limited repressuring in the reservoir, and
- Porosity and saturation (as determined from analysis of wireline logs) do not accurately reflect reservoir quality and performance.

Production at the NRU is from the Lower Permian Glorieta and Clear Fork Carbonates. The reservoir interval is thick, with a gross interval of approximately 1,400 ft (427 m), and more than 90% of the interval has uniform lithology (dolostone). Unfortunately, the interval is characterized by a complex pore structure that results in extensive vertical layering. The reservoir is characterized by discontinuous pay intervals and high residual oil saturations (35% to 60%, based on steady-state measurements of relative permeability). The most important, immediate problem in the field is that porosity and saturation determined from logs do not accurately reflect reservoir quality and performance.

Given these reservoir characteristics, the ability to accurately target infill well opportunities is critical as blanket infill drilling will be uneconomic in most cases. For this particular case study, the cost-effective, and readily available reservoir characterization tools outlined in this work allowed us to optimally target specific well locations. After implementing a targeted infill program, the total production at the NRU has been increased approximately 30 percent, while the total well count was increased by only 7 percent.

HISTORICAL BACKGROUND

The NRU is located in Gaines County, west Texas, on the northeastern margin of the Central Basin Platform (**Figure 1**). The hydrocarbon-bearing interval extends from the base of the Glorieta to the base of the lower Clear Fork, between correlative depths of approximately 6,160-7,200 ft (1,877-2,195 m). The unit includes 5,633 surface acres (2253 hectares, 22.8 km^2) containing a total of 270 wells (November, 1996). This includes 156 active producing wells, 113 active injection wells, and 1 fresh water supply well.

Development and Production History

Production from the North Robertson field area began in the early 1950s with 40-acre (16-hectare) primary well development. This 40-acre primary development resulted in 141 producing wells by 1965. The NRU was formed effective March, 1987 for the purpose of implementing waterflood and infill drilling operations and nominal well spacing was reduced from 40 acres to 20 acres (8 hectares). Secondary recovery operations were initiated after unitization and in conjunction with infill drilling. Most of the 20-acre infill drilling was completed between unitization and the end of 1991.

The contacted original oil-in-place from material balance decline type curve analysis is estimated to be 262 million bbls (41.66x10^6 m^3), with an estimated ultimate recovery factor of approximately 15% (primary and secondary) based on the current production and workover schedule. **Figure 2** presents the production and injection history of the unit from development in 1956 through November 1996. The total oil and water volumes produced and injected since field development are tabulated below:

Time Frame	Oil Produced (mil.bbls)	Water Produced (mil. bbls)	Water Injected (mil. bbls)
As of 1987 (primary)	17.5	8.2	0.0
1987-1996 (secondary)	9.3	28.3	64.2

Prior to 10-acre (4-hectare) infill drilling, the total unit production rates were approximately 2,740 STBO/D (436 m^3/day), 1,130 MSCF/D gas (32,000 m^3/day), and 12,230 BW/D (1,945 m^3/day). Water injection prior to the infill program was approximately 19,000 BWI/D (3,021 m^3/day), with injection water comprised of produced water, and fresh water from the Ogallala aquifer obtained from a water supply well within the unit.

The eighteen (14 producers, 4 injectors) 10-acre infill wells that were drilled during the second and third quarters of 1996 have increased unit production rates to 3,350 STBO/D, 1,700 MSCF/D gas, and 13,500 BW/D. Current injection at the unit is approximately 19,600 BWI/D.

The well configuration at the NRU is an East-West line drive pattern (staggered five-spot), and was developed for optimum injectivity and pressure support. Sweep efficiency is difficult to quantify due to differences in depositional environments throughout the unit. Fortunately, these differences are easily identified on the basis of reservoir rock type.

GEOLOGIC STUDY

This geological/petrophysical reservoir characterization of the NRU involved the following methodologies (Davies and Vessell, 1996a,b):

- Development of a depositional and diagenetic model of the reservoir,
- Definition of "rock types" based on pore geometry and development of the rock-log model,
- Rock type extension to non-cored wells using the rock-log model,
- Definition of flow units and cross-flow barriers, and
- Mapping of reservoir parameters (thickness, ϕh, kh, and hydrocarbon pore volume) and rock type for each flow unit.

The purpose of the geological/petrophysical portion of our study was to identify and map individual hydraulic flow units (HFU's) to evaluate the potential for continued development drilling. Flow units had to be readily identified using wireline logs as core data are sparse (8 wells). Thus, the fundamental reservoir description was well log-based. However, because values of porosity and saturation derived from routine well log analysis do not accurately identify productive rock in most shallow-shelf carbonates, it was necessary to develop a core- or rock-log model that allowed for the prediction of another producibility parameter--in this case formation permeability.

A geologic model was developed for the reservoir, based fundamentally on the measurement of pore geometrical parameters. Pore-level reservoir modeling gave improved accuracy in the prediction of rock types, permeability, and the identification of flow units. Pore geometry attributes were integrated with well log data to allow for log-based identification of intervals of rock with different capillary characteristics, as well as the prediction of permeability throughout the unit.

No new wells were drilled to aid the reservoir description. The existing database consisted of conventional cores from eight wells, and relatively complete log suites in 120 wells which consisted of:

- Gamma ray, GR
- Photoelectric capture cross-section, PE
- Compensated neutron porosity, ϕ_N
- Compensated formation bulk density, ρ_b
- Dual laterolog (LLD and LLS--deep/shallow resistivities)
- Borehole caliper

Pore Geometry Modeling

At the NRU, we found no strong relationship between porosity, permeability, and depositional environment as indicated by the "shot gun" scatter of data points shown in **Figure 3**. Different environments exhibit similar ranges of porosity and permeability, which is not surprising as the facies have undergone significant diagenetic alteration of pore geometry after deposition. Thus, there is no fundamental relationship between depositional environment and permeability. This is a common problem in many diagenetically-altered reservoirs.

Analysis of 3D pore geometry data allowed our reservoir characterization efforts to be pore system oriented. The resulting reservoir models were based on characteristics of the pore system. Analysis of pore geometry involved the identification of individual pore types and rock types.

In a previous work, Davies and Vessell (1996a) used the quantitative analysis of pore geometry to develop the vertical reservoir layering profile of the reservoir (*i.e.*, to identify vertical compartmentalization) at the NRU. The authors found that integrating pore scale observations with depositional and diagenetic data allows for the determination of the areal compartmentalization and permeability distributions within the reservoir.

Pore Types: The determination of pore types in a reservoir requires the use of rock samples (conventional core, rotary sidewall cores, and cuttings samples in favorable circumstances). In this study, analyses were based on 1 inch "quick" plugs removed from conventional cores. Individual pore types were classified in terms of the following parameters:

Pore Body Size and Shape: Determined using scanning electron microscope (SEM) image analysis of the pore system (Clelland and Fens, 1991).

Pore Throat Size: Determined through capillary pressure analysis and SEM analysis of pore casts (Wardlaw, 1976).

Aspect Ratio: The ratio of pore body to pore throat size. This is a fundamental control on hydrocarbon displacement (Wardlaw, 1980; Li and Wardlaw, 1986).

Coordination Number: The number of pore throats that intersect each pore (Wardlaw and Cassan, 1978).

Pore Arrangement: The detailed distribution of pores within a sample (Wardlaw and Cassan, 1978).

These parameters were combined to yield a classification of the various pore types in these rocks (**Table 1**). Pore types were identified in each core sample (350 samples in this study). Commonly, each sample (1 inch diameter core plug) contained several different pore types. It was therefore necessary to group pore types into rock types.

For each sample, the volumetric proportion of each pore type was determined using SEM-based image analysis (Clelland and Fens, 1991). Because the pore throat size is known for each pore type, it was possible to develop a pseudo-capillary pressure curve for each sample using the well known relation (Thomeer, 1983):

$$p_c = \frac{214}{d}, \qquad (1)$$

for which p_c is mercury-air capillary pressure in psia and d is pore throat diameter in microns (10^{-6} m).

The validity of the geologically-determined rock types was evaluated using mercury capillary pressure analysis of selected samples. Our results revealed differences between the rock types in terms of the measured capillary characteristics (**Table 2**). Such cross-checks allow for independent validation of the pore geometrical classification of rock types. Mercury capillary pressure data are also used to aid in the determination of pore throat sizes (Calhoun, 1960).

Rock Types: A "rock type" is an interval of rock characterized by a unique pore structure (Archer and Wall, 1986), but not necessarily a unique pore type. In this study, *eight rock types were identified*, based on the relative volumetric abundance of each pore type (**Figure 4**). Each rock type is characterized by a particular assemblage (suite) of pore types (Ehrlich and Davies, 1989). For example, Rock Type 1 is dominated by Pore Type A, while Rock Type 2 contains few pores of Type A and is dominated by Pore Types B and C. Identification of rock types is fundamentally important because porosity and permeability are related within a specific pore structure (Calhoun, 1960), as shown for Rock Type 1 in **Figure 5**.

Porosity-Permeability Relationship

At the NRU, the basic relationship between porosity and permeability exhibits a considerable degree of scatter (up to 4 orders of magnitude variation in permeability for a given value of porosity). In contrast, the porosity and permeability are closely related for each rock type (**Figure 5**). Permeability calculations on the basis of rock type have an error range of less than one-half decade for most samples. Regression equations for permeability as a function of porosity were developed for each rock type to quantitatively define each relationship (using log-log plots to avoid zero porosity intercepts). These equations were used in the field-wide prediction of permeability using well logs (permeability being a function of porosity <u>and</u> rock type).

Average values of porosity and permeability are given for each rock type in **Table 3**. We immediately note that the highest porosity rocks at the NRU <u>do not</u> exhibit the highest permeability. The principal pay rock at the NRU is Rock Type 1. Rock Type 1 has significantly lower values of porosity than Rock Type 4 (flow barrier). This characteristic has important implications in terms of selecting completion intervals. Given our observations, the zones with the highest porosity should not always be the principal targets in this Clear Fork reservoir.

Rock-Log Model

Analysis of pore geometries reveal that eight rock types occur in the NRU. Six of the rock types are dolostone, one is limestone (non-pay--structurally low and wet in this field), and one is shale (**Table 3**). Individual rock types can be recognized using specific "cut-off" values based on analysis of environmentally corrected and normalized well log responses and using the comparison of core-based determination of rock type.

The well log responses used to isolate the eight different rock types for the NRU study were:

- ρ_{maa} versus U_{maa} with gamma ray (**Figure 6**)
  - This data plot allows the discrimination of dolostone, limestone, anhydritic dolostone, siltstone, and shale
  - Can be used to identify "pay" vs. "non-pay" reservoir rock
- Shallow and deep laterolog resistivities and porosity (**Figure 7**)
  - Provides discrimination of "pay" Rock Types 1-3.

The rock-log model was first developed using data from only 5 cored wells. Subsequently the model was extended to include the 3 remaining cored wells. Evaluation of cored intervals reveals successful discrimination (>80%) of each of the principal rock types (Rock Types 1-3) despite the fact that wells were logged by different companies at different times. Misidentification of Rock Type 1 results in identification of Rock Type 2, while misidentification of Rock Type 2 results in identification of Rock Type 1. Thus, there is no significant misidentification of the dominant rock types by logs over the cored intervals. The model has been extended to all wells with sufficient log suites in the field (120 wells in the NRU). Specific algorithms allow for rock type identification on a foot-by-foot basis in each well.

As we showed previously (**Figure 5**), permeability is a function of both rock type and porosity. We have established that rock type and porosity can be determined from well log responses alone. Therefore, permeability can, in principle, be predicted using only well log data. This gives us the ability to develop a vertical layering profile based on rock type and permeability in cored and non-cored wells.

Improving our understanding of the relationship between porosity and permeability has been one of the key efforts of our geologic work. Our approach has been to integrate all geologic and engineering data in an attempt to refine our existing porosity-permeability algorithms, and to redefine flow unit boundaries. Now that we have finished the infill drilling program and loaded all new core and open-hole log data into our database, we can begin to update our porosity-permeability relationships and flow unit definitions.

Early indications are that by using multiple geologic "filters" it is possible to dramatically reduce the scatter on our porosity versus permeability crossplots, thereby providing us with more robust algorithms. "Filters" include devices such as depositional environment data, shallowing upward sequence tops, rock type data, mud log data, and numerous open-hole log responses (PE, Spectral Gamma Ray, Invasion Profile, etc.).

Hydraulic Flow Units

Individual HFU's were identified based on the integration of the data for the distribution of rock types, petrophysical properties (in particular, permeability and fluid content) and depositional facies. Evaluation of this data for 120 wells revealed that rock types are not randomly distributed, rather the principal reservoir rocks (Rock Types 1, 2, and 3) generally occur in close association, and typically alternate with lower quality rocks (*e.g.*, Rock Types 4, 6, 7 and 8). Correlation of rock types between wells reveals an obvious layering profile in which 12 distinct layers, or HFU's, are distinguishable at the NRU. Correlation of these layers is aided by a knowledge of the distribution of depositional environments as there is a general relationship between depositional environment and rock type. Rock Types 1 and 2 are more common in high energy deposits (shoals, sand flat, forebank). Rock Types 3 and 4 are common in low energy deposits (supratidal, tidal flat, lagoon).

Maps were prepared for each of the HFU's to illustrate the distribution of important petrophysical parameters. The distribution of the principal rock types for each HFU was also mapped. This allowed for rapid identification of areas of the field dominated by either high or low quality reservoir.

There is a general tendency at the NRU for the higher quality rocks (Rock Types 1 and 2) to occur in discrete trends on the NE (high energy) edge of the unit while relatively lower quality rocks (Rock Types 3 and 4) occur in SW (low energy) portions of the unit. Within these general trends, variations exist in the distributions of permeability. These variations are important as they result in compartmentalization of the reservoir. There are no faults in the NRU--compartmentalization is entirely stratigraphic and is the result of areal variations in the distributions of individual reservoir rock types.

New Data - Infill Drilling Program

Additional Whole Core: We took 2,730 feet of core in four new wells as part of an intensive effort to collect needed rock data (Kamis et al., 1997). The data will be used to help quantify the extent of small scale vertical and lateral heterogeneity, refine the depositional model, improve our understanding of the relationship between porosity and permeability, and help us choose additional 10-acre infill drilling locations within the NRU Clear Fork Formation.

We attempted to cut cores continuously through the entire Clear Fork section. Parts of the section were not cored due to significant mechanical difficulties caused by very long core times--often greater than 200 minutes per foot. This continuous core gives us the ability to make foot by foot comparisons of reservoir quality, rock type, and depositional environment, which ultimately will help us correctly model fluid movement within the reservoir.

Rock Fabrics: Based on our description of the new core, we have described four basic rock fabrics:

1) Homogeneous--which is made up of relatively uniformly distributed lateral and vertical porosity and permeability. The best

example of this type of rock fabric is found within selected portions of the upper Clear Fork. We are not implying that this zone is perfectly homogeneous like some silica clastic sands, however, this layer is much closer to this type of homogeneity than all other zones in the Clear Fork.

2) Fractured--which is made up of solution collapse breccias as described above. Fractures are 2-4 inches in length and very roughly estimated to be 4-6 inches apart. Not all of these fractures are open, as many have been plugged with anhydrite. Portions of the middle Clear Fork are a good example of this fabric.
3) Bimodal--which is made up of two distinct pore sizes. The larger size pores are typically formed from the dissolution of fossil debris, and the smaller pores are typically intercrystalline in origin.
4) Heterogeneous--which is made up of anhydrite nodules, and porous dolostone. This fabric is common throughout much of the Clear Fork/Glorieta section. The size and distribution of these anhydrite nodules vary dramatically.

Mud Logs: We have captured continuous reading of all mud gas components while drilling, and loaded the data into a computer database and depth corrected it. In addition, we have started research into the applicability of using mud gas component ratios to estimate fluid content. It is hoped that flushed zones will have uniquely different ratios than previously uncontacted oil zones.

We have noticed also that the mud log is an excellent tool for locating the intervals that contribute most to production. In this particular shallow-shelf carbonate reservoir, it would appear that the pay intervals of interest could probably be cost-effectively defined simply by using the mud log and a base porosity and resistivity log. It is essential that a high quality and reliable mud logging company be chosen to do the work. Mud loggers with previous experience in the formation being drilled is also an important component in getting reliable data. If an operator requires more detailed information regarding porosity types, rock quality, and fluid distributions, then additional information must obviously be gathered.

Open-Hole Logs: The base logging suite for the 10-acre infill wells currently consists of a Dual Laterolog, Micro Laterolog or Micro-Spherically Focused Log (R_{xo} device), Compensated Neutron Log, Compensated Spectral or Litho-Density Log (includes PE), Spectral Gamma Ray Log, and a Sonic Log. We have utilized several potentially useful modern open-hole logging tools in addition to our normal logging suite in an attempt to more accurately characterize permeability, fluid content, and rock fabric. Some of these are summarized below:

High Frequency Dielectric Log: The high frequency (200 MHz) dielectric log yields a salinity-independent measure of fluid distributions in the flushed zone. This is of paramount importance in areas such as the North Robertson Unit that are currently under active waterfloods. The dielectric tool produces a much more accurate representation of pay intervals than can be obtained from the usual low frequency flushed zone resistivity devices, such as the MLL or MSFL, which do not always do a good job of differentiating between residual and movable hydrocarbons.

This device works extremely well in formations with mixed lithology, and if run in combination with a low frequency flushed zone resistivity device, yields a rock textural parameter that can be used to determine the type of porosity present (intergranular, vuggy, or fracture), which directly affects the producibility of any particular interval.

NMR Log: Nuclear Magnetic Resonance (NMR) logs were recorded over selected sections of two cored wells in an effort to obtain permeability, lithology-independent porosity, pore size distribution, and fluid saturation distribution from a single log. Most of the preliminary NMR work has been performed to differentiate between oil and water in low-resistivity clastics, however, several recent projects performed in the Permian Basin area are adding to the understanding of NMR responses in high-resistivity carbonate reservoirs.

This device gave a good approximation of permeability, pore size, and the location of free hydrocarbons, however, data acquisition and processing are costly, and initially need to be closely calibrated with core. The distribution of free and bound fluids in the rock pores obtained from NMR analysis of selected core samples from the two wells indicated that the reservoir is oil wet. This fluid distribution was then used in the processing of the raw log data to yield a visual representation of the pore and fluid distribution in the reservoir.

ENGINEERING STUDY

Comparing Geological And Petrophysical Properties With Historical Performance

If the pore modeling and rock typing exercises are performed properly, the resulting rock type and permeability distributions associated with the reservoir should mirror the historical production performance. The petrophysical parameter and rock type maps resulting from our geological-petrophysical study were compared to the performance maps derived from the results of decline type curve analyses and pressure transient tests. This provided us with a rapid, cost-effective, and accurate method for targeting infill well locations at the NRU (Davies et al., 1997).

In order to verify the results of the rock-log modeling, long-term production and injection data were analyzed using material balance decline type curves, and the results were mapped for comparison to the petrophysical parameter and rock type maps generated from the work summarized above. In addition, the results of pressure transient tests (average reservoir pressure and flow characteristics) were also incorporated to help correlate the reservoir rock type and historical performance.

Other applications for the decline curve results are:

- Reservoir delineation, recovery and rate forecasting,
- Maps of reservoir performance potential,
- Estimating efficiency of reservoir drive mechanism(s),
- Analogy with offset properties, and
- Calibrating reservoir simulation models.

Material Balance Decline Type Curve Analysis

An initial study of the 40- and 20-acre producing wells, and 20-acre water injection wells was performed using rigorous material balance decline type curve methods (Doublet et al., 1994; Doublet and Blasingame, 1996). Some of the goals of these analyses were:

- To analyze long-term production data as well as injection rate and pressure data to evaluate reservoir performance.
- To provide the same flow characteristics associated with the acquisition of field data and without well "downtime."

The results of these analyses include the following:

- In-place fluid volumes:
  - Contacted original oil-in-place,
  - Movable oil or injectable water at current conditions, and
  - Reservoir drainage or injection area.
- Reservoir properties (based on performance):
  - Skin factor for near-well damage or stimulation, *s*, and
  - Formation flow capacity based on production performance, *kh*.

An example of a decline type curve match for a hydraulically-fractured producing well is shown in **Figure 8**.

We focused on using data that operators acquire as part of normal field operations (*e.g.*, production rates from sales tickets and pressures obtained from permanent surface and/or bottomhole gauges). In most cases, these will be the only data available in any significant quantity, especially for older wells and marginally economic wells, where both the quantity and quality of <u>any</u> types of data are limited.

This approach of using production and injection data eliminates the loss of production that occurs when wells are shut in for pressure transient tests, and provides analysis and interpretation of well and field performance *at little or no cost to the operator*. This technique allows us to evaluate reservoir properties quickly and easily, and provides us with an additional method for locating the most productive areas of the reservoir.

The results of the decline type curve analyses were used to generate reservoir quality maps of contacted original oil-in-place (OOIP), permeability-thickness (*kh*), and estimated ultimate recovery (EUR) for both the original 40-acre (primary), and 20-acre (secondary) producing wells as shown in **Figures 9-12**.

Pressure Transient Analysis

A unit-wide pressure transient data acquisition program was initiated prior to 10-acre infill drilling. The purpose of this study was to:

- Obtain sufficient data for a representative comparison with tests recorded prior to the initiation of water injection,
- Provide additional data for simulation history matching,
- Estimate completion/stimulation efficiency,
- Identify the best areas of the reservoir with regard to pressure support, and
- Identify any other major problems related to waterflood sweep efficiency.

Our data acquisition program consisted of taking 10 pressure buildup tests (on producing wells) and 13 pressure falloff tests (on injection wells). The locations for these tests were well distributed throughout the unit in order to obtain a representative, unbiased sampling.

The estimated formation flow characteristics (permeability, skin factor, fracture half-length) compare very well with the results from the pre-waterflood transient tests. The major difference we noted was the relative change in average reservoir pressure throughout the unit after eight years of continuous water injection. A reservoir pressure map for the 1995 tests (from pressure buildup and falloff tests) is shown in **Figure 13.**

Optimizing Well Completions and Stimulations At The NRU

Another benefit of the geologic analyses that we performed on the new and existing whole core was the more accurate targeting of discrete producing intervals within the 1,400 ft Glorieta/Clear Fork section. For the most part these intervals coincide with zones containing a predominance of Rock Type 1 (recall that this is our main pay rock type). These are zones of relatively high permeability and porosity, which are separated by larger intervals of lower permeability and porosity rock that act as barriers or source beds for the higher quality reservoir sections. At North Robertson, the discrete productive intervals which we focused on during completion include:

- Lower Clear Fork: ±7,000-7,180 ft
- Middle Clear Fork: ±6,350-6,500 ft
  ±6,770-6,900 ft
- Upper Clear Fork: ±6,160-6,250 ft

We have utilized three-stage completion designs to keep the treated intervals between 100 and 250 ft. We have performed both CO_2 foam fracs and conventional cross-linked borate fracs. All well's rates have held up extremely well over time for both hydraulic fracture designs. The major factor controlling initial potential appears to be confinement of the vertical completion interval and localized reservoir quality. The advantages of each type of frac design are listed below:

CO_2 Fracs:

- exceptionally clean frac fluid
- increased relative oil permeability
- created solution gas drive reduces cleanup requirements
- formation of carbonic acid for near-well stimulation
- reduction in interfacial tension helps remove water blocks

Cross-linked Borate Fracs:

- exceptionally clean frac fluid
- low fluid loss without formation-damaging additives
- excellent proppant-carrying capacity
- polymer-specific enzyme breaker aids in post-frac cleanup
- 90% of original fracture conductivity retained

Pre-frac cleanup acid jobs have been performed to remove near-well damage using between 1000 and 3000 gallons of 15% acid. Most intervals have been perforated for limited-entry fracturing (> 2 bbl per perforation), with average injection rates between 30 and 40 barrels per minute, depending on the size of the interval. The size of the frac jobs has ranged from 35,000 gallons of fluid and 55,000 lbs of 16/30 sand to 70,000 gallons of fluid and 150,000 lbs of 20/40 sand. Resin-coated sand has been "tailed-in" for all frac jobs to reduce sand flowback during production. The conventional fracs have been flowed back immediately at 1 barrel per minute to induce fracture closure, while the foam fracs have been shut-in 2 to 5 days after stimulation to allow the CO_2 to soak into formation.

All hydraulic fracture jobs were designed to yield fracture half-lengths of approximately 200 ft. Post-frac pressure transient tests performed over specific completion intervals indicated that we are obtaining fracture half-lengths of approximately 120 ft with average radial flow skin factors of approximately -5.25.

The result of these improved completion techniques is shown in **Figure 14**. The average three-month initial potential (IP's) for these new infill wells are two to three times greater than the IP's from the previous drilling and completion programs at the NRU.

Short-term pressure drawdown tests were used to measure formation flow characteristics in the new producing wells. We recorded drawdown rather than buildup tests to avoid shutting in recently completed wells. These tests were being recorded over individual completion intervals (i.e., lower, middle, or upper Clear Fork), and were used to estimate the completion efficiency and the relative contribution of each zone to total production.

Well Testing

The interval well test results indicated that the middle and upper Clearfork intervals are much more significant contributors to total production than was previously thought. At this point it appears that each interval's <u>approximate</u> contribution to total oil production is as follows:

	Sect. 327	**Sec. 329**
Upper Clear Fork	20%	10%
Middle Clear Fork	50%	65%
Lower Clear Fork	30%	25%

Reserves - Incremental vs. Accelerated

Early results indicate that approximately 65% of the production from the new infill wells is incremental, and approximately 35% may be acceleration of existing reserves. The new wells account for approximately 900 STBO/D of the total unit production, and the amount of incremental production since the Field Demonstration was implemented is between 600 and 700 STBO/D. On an individual well basis, most of the additional production in Section 329 of the unit appears to be due to acceleration of existing reserves, while most of the additional production in Sections 326 and 327 appears to be incremental. These trends were predicted prior to drilling on the basis of differing reservoir rock types that occur in the two areas. The Section 329 infill area is dominated by grainstone shoal facies with fairly good permeability and porosity characteristics (Rock Type 1). The reservoir within Sections 326 and 327 is dominated by lagoonal facies with good storage capacity (porosity), but relatively lower permeability and connectivity (Rock Type 3). We will continue to monitor and report individual well producing characteristics in an effort to quantify incremental reserves added via infill drilling.

CONCLUSIONS

As a result of this study we hope to identify useful and cost-effective methods for the exploitation of the shallow-shelf carbonate (SSC) reservoirs of the Permian Basin. The techniques that we outline for the formulation of an integrated reservoir description apply to all oil and gas reservoirs, but are specifically tailored for use in the heterogeneous, low permeability carbonate reservoirs of west Texas.

1. Measurement of pore geometry parameters allows for the improved prediction of permeability and permeability distribution from wireline logs in partially cored intervals, and in adjacent uncored wells. This approach improves the prediction of reservoir quality in non-cored intervals and results in improved well completions and EOR decisions.
2. Detailed pore geometry attributes allow for better definition of hydraulic flow units. These attributes can be related to well log responses, which allows for the development of a field-wide, log-based reservoir model.
3. The material balance decline type curve techniques summarized in this work provide very good estimates of reservoir volumes (total and movable), and reasonable estimates of formation flow characteristics. Using this approach to analyze and interpret long-term production and injection data is relatively straightforward and can provide the same information as conventional pressure transient tests, without the associated costs of data acquisition, or loss of production.
4. From our comparison of geological and petrophysical parameters with historical production performance, we believe that the producing characteristics of individual wells are a direct function of the local rock type distribution. The reservoir depletes and repressures as a function of reservoir quality (rock type), throughout all areas of the unit.
5. We identified the regions in the unit with additional reserves potential (accelerated or incremental), as well as those areas in which infill drilling is not likely to be economic.
6. We believe that uniform infill drilling is neither prudent, nor warranted, given the stratigraphic compartmentalization and irregular permeability distributions in this reservoir. Infill drilling should be restricted to:
   a) Areas of the field that exhibit Rock Types 1, 2, and 3 as dominant, with good permeability and hydrocarbon pore volume (HPV) characteristics, high primary and secondary recovery, and
   b) Areas of poor reservoir continuity with acceptable porosity and permeability values, with a significant abundance of Rock Types 1, 2, or 3, and good primary, yet poor secondary recovery characteristics.
7. If the productive intervals within the reservoir can be better defined based on core and well log analyses, then completion efficiency (initial potential and reserves recovery) can be increased and completion costs can be decreased.

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Table 1 - Pore type and classification at the NRU.

Pore Type	Size, μm	Shape	Coordination Number	Aspect Ratio	Pore Arrangement	Geologic Description
A	30-100	Triangular	3-6	50-100:1	Interconnected	Primary interparticle
B	60-120	Irregular	<3	200:1	Isolated	Shell molds and vugs
C	30-60	Irregular	<3	100:1	Isolated	Shell molds and vugs
D	15-30	Polyhedral	~6	<50:1	Interconnected	Intercrystalline
E	5-15	Polyhedral	~6	<30:1	Interconnected	Intercrystalline
F	3-5	Tetrahedral	~6	<20:1	Interconnected	Intercrystalline
G	<3	Sheet/slot	1	1:1	Interconnected	Interboundary sheet and intercrystalline pores

Table 2 - Capillary characteristics by rock type based on mercury injection.

Rock Type	Entry Pore Throat Radius, μm	Displacement Pressure, psia	Ineffective Porosity (porosity invaded by Hg at $p_c > 500$ psia), %
1	7.6-53.3	2-10	8.2-29.6
2	2.7-3.6	30-40	23.1-49.5
3	0.4-1.3	80-300	61.6-72.3
4*	1.8	60	88
5	1.1-1.8	60-150	21.7-57.2
6*	0.1	800	100

* - Only one (1) measurement

Table 3 - Porosity, permeability, and lithology by rock type.

Rock Type	Median Porosity, %	Median (Hg/air) Permeability, md	Lithology	Reservoir Quality	Cross-flow Barrier Quality
1	4.0	0.70	Dolostone	Excellent	Poor
2	5.6	0.15	Dolostone	Good	Poor
3	3.5	0.39	Dolostone	Moderate	Moderate
4	7.5	0.01	Dolostone	Poor	Moderate
5*	5.8	0.40	Limestone	Good (water-bearing)	Poor
6	1.0	<0.01	Anhydritic Dolostone	None	Good
7	2.3	<0.01	Silty Dolostone	None	Good
8	--	--	Shale and argillaceous dolostone	None	Good

* - Structurally low and wet at the NRU

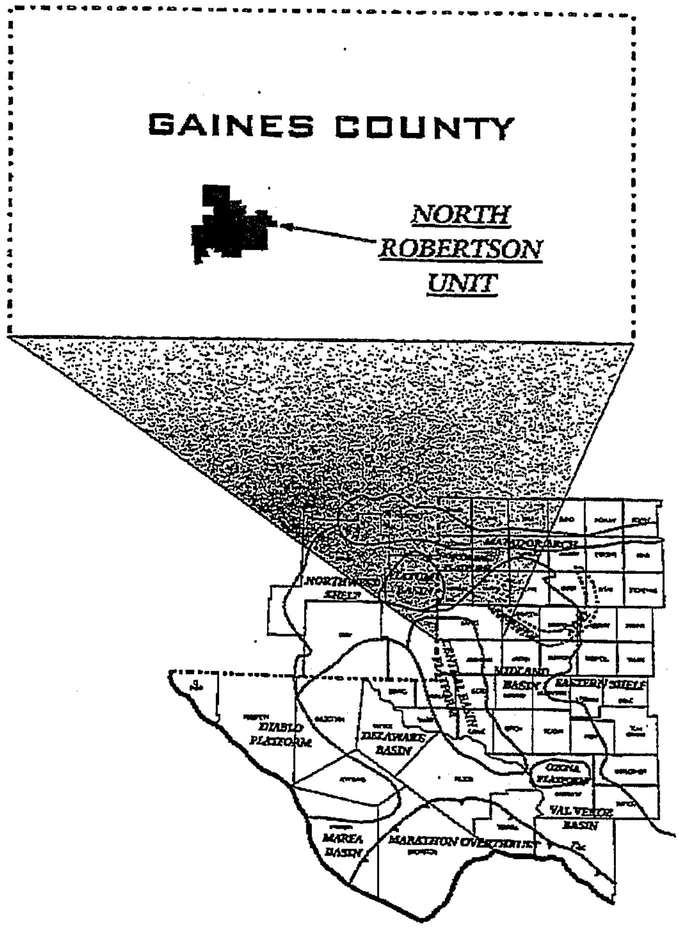

Figure 1 - Regional map showing location of the North Robertson (Clear Fork) Unit.

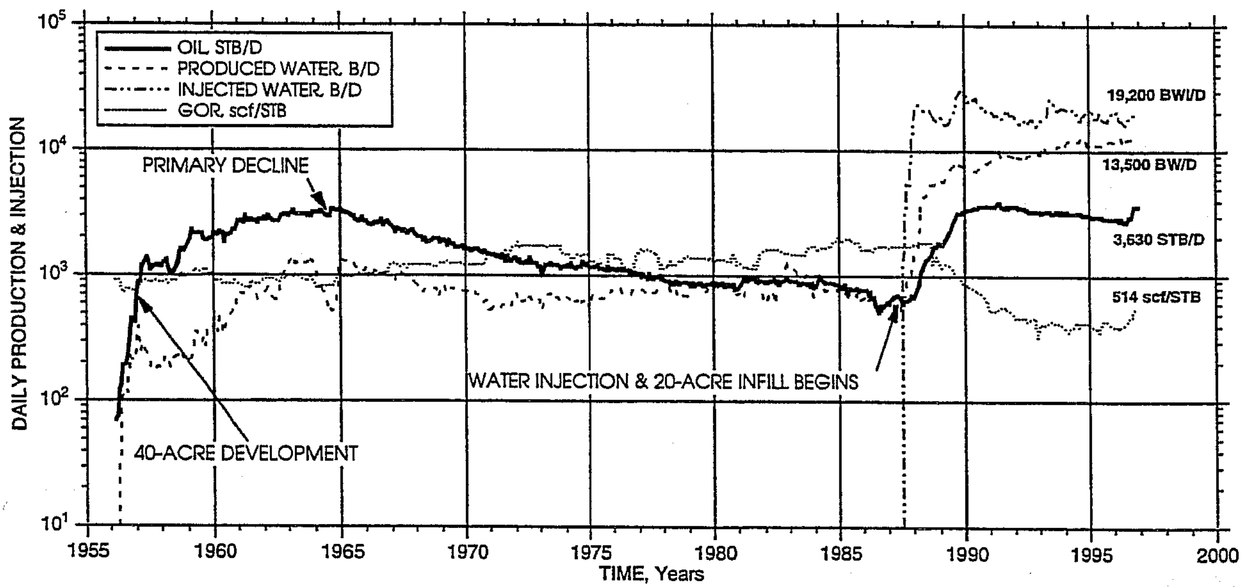

Figure 2 - NRU production and injection history.

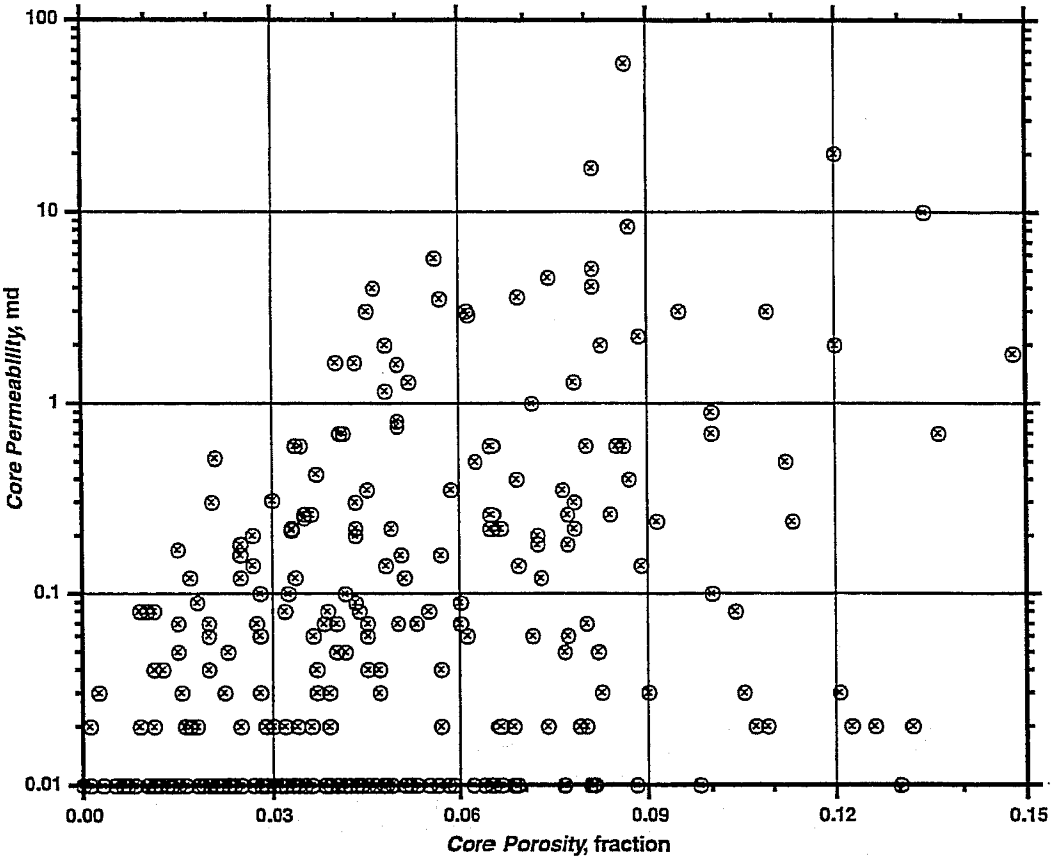

Figure 3 - Porosity-permeability relationships - all core data.

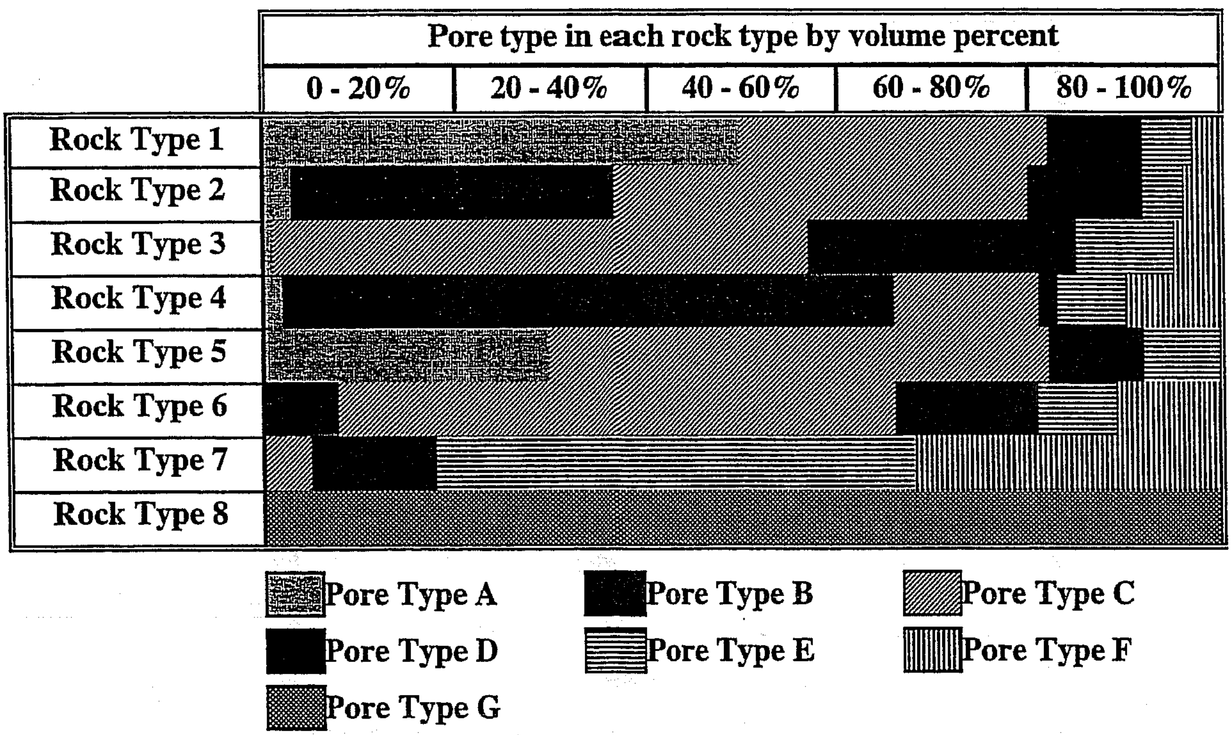

Figure 4 - Volumetric proportions of pore types in each rock type.

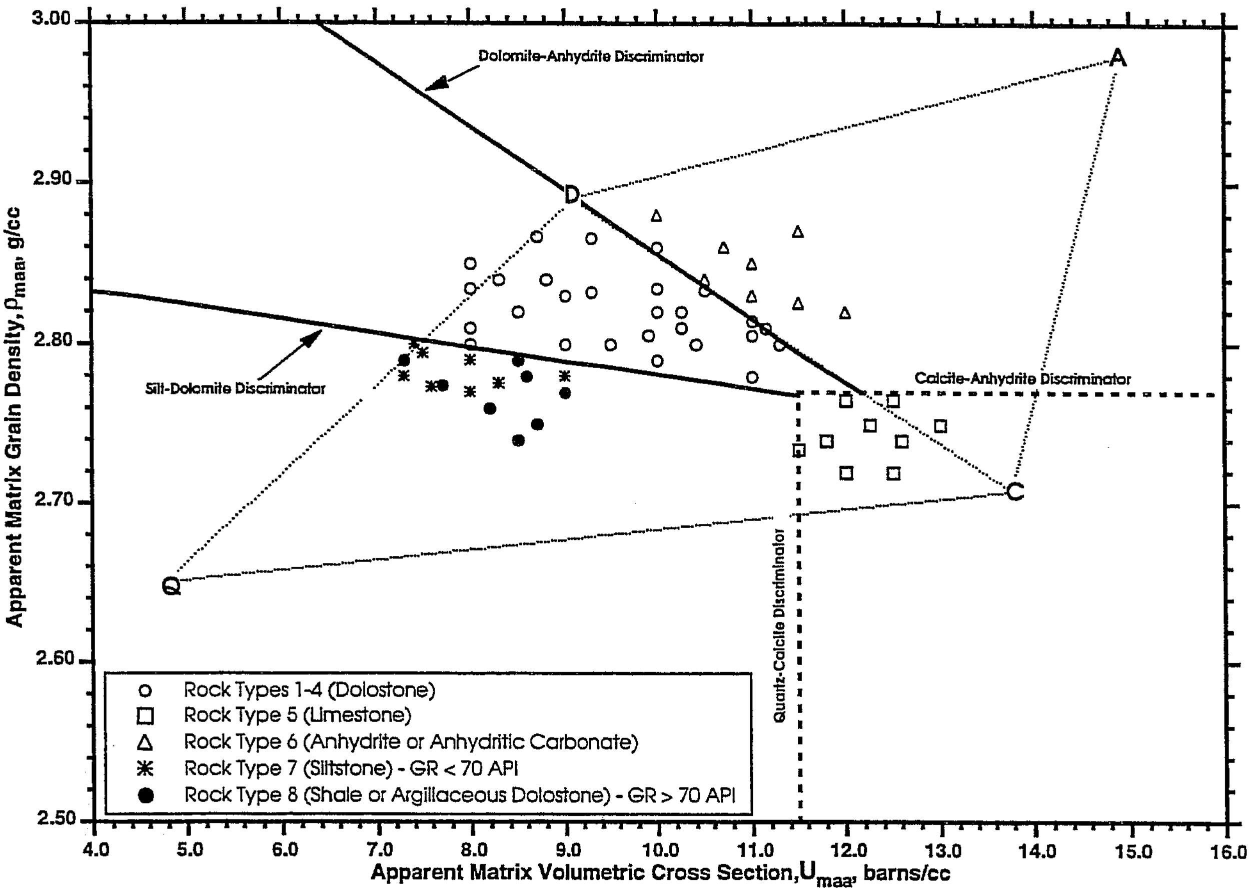

Figure 5 - Differentiating "pay" from "non-pay" reservoir rocks.

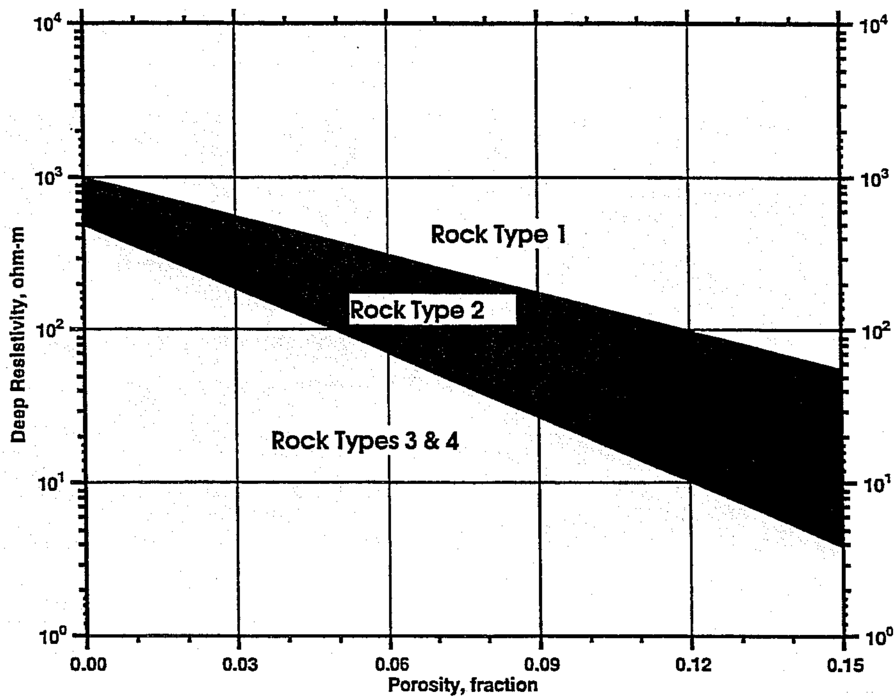

Figure 6 - Differentiating between "pay" reservoir rock types.

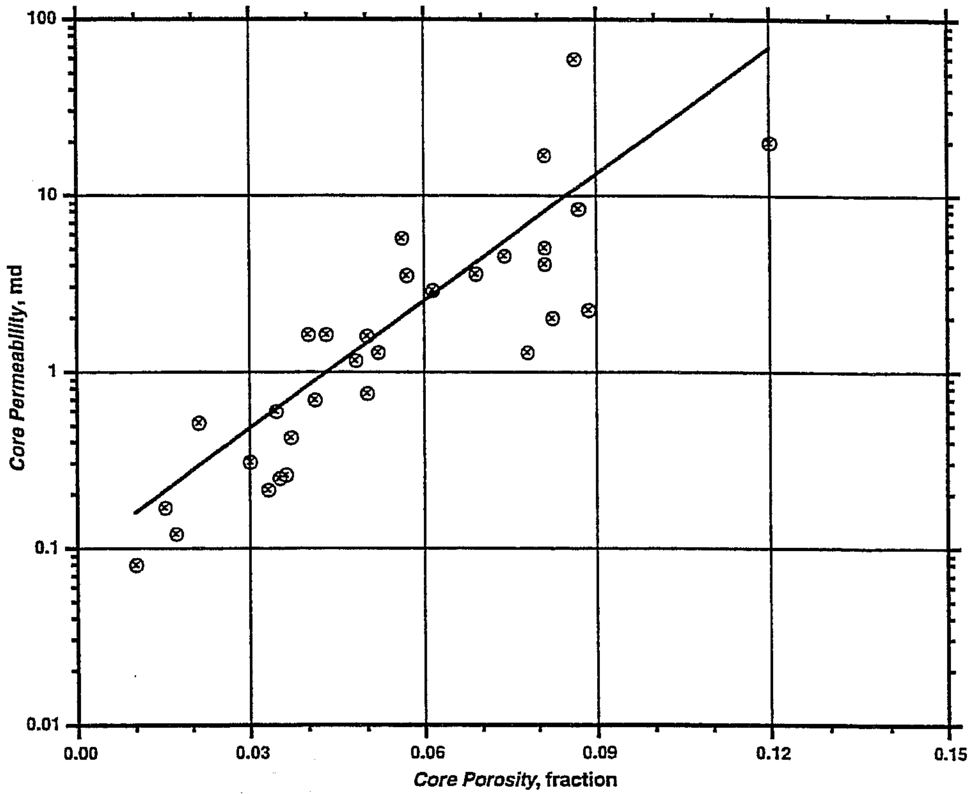

Figure 7 - Porosity-permeability relationship for one rock type.

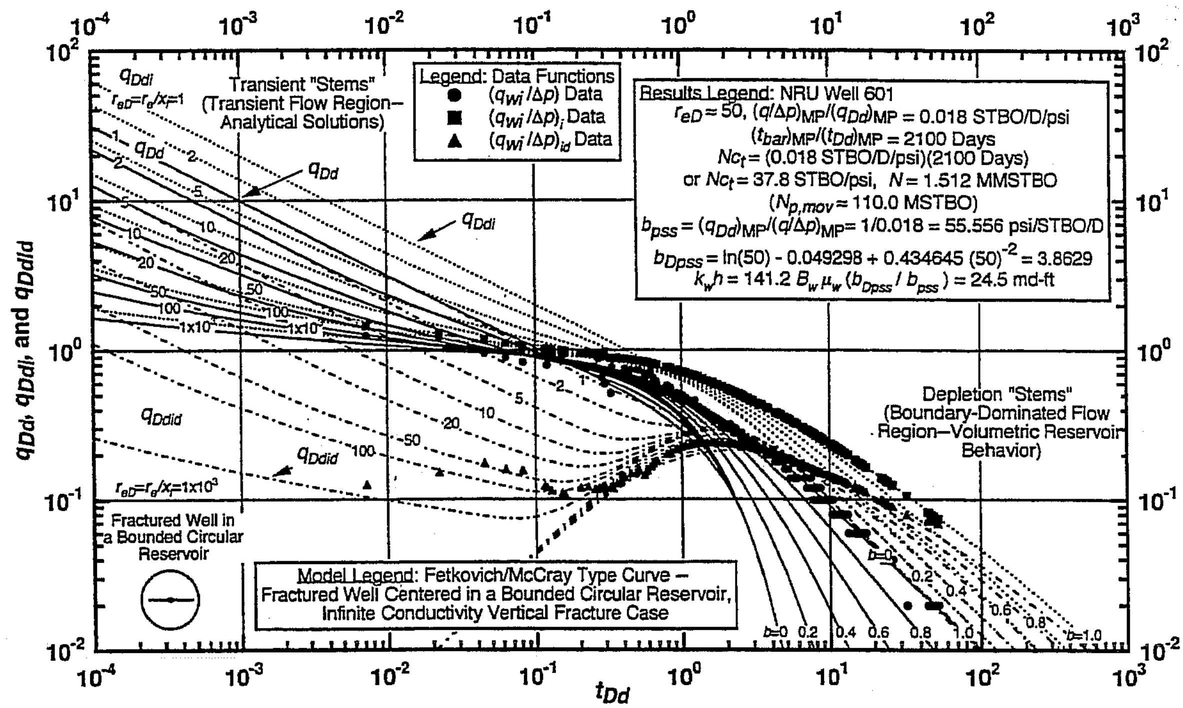

Fig. 8 - Fetkovich-McCray material balance decline type curve match (fractured well).

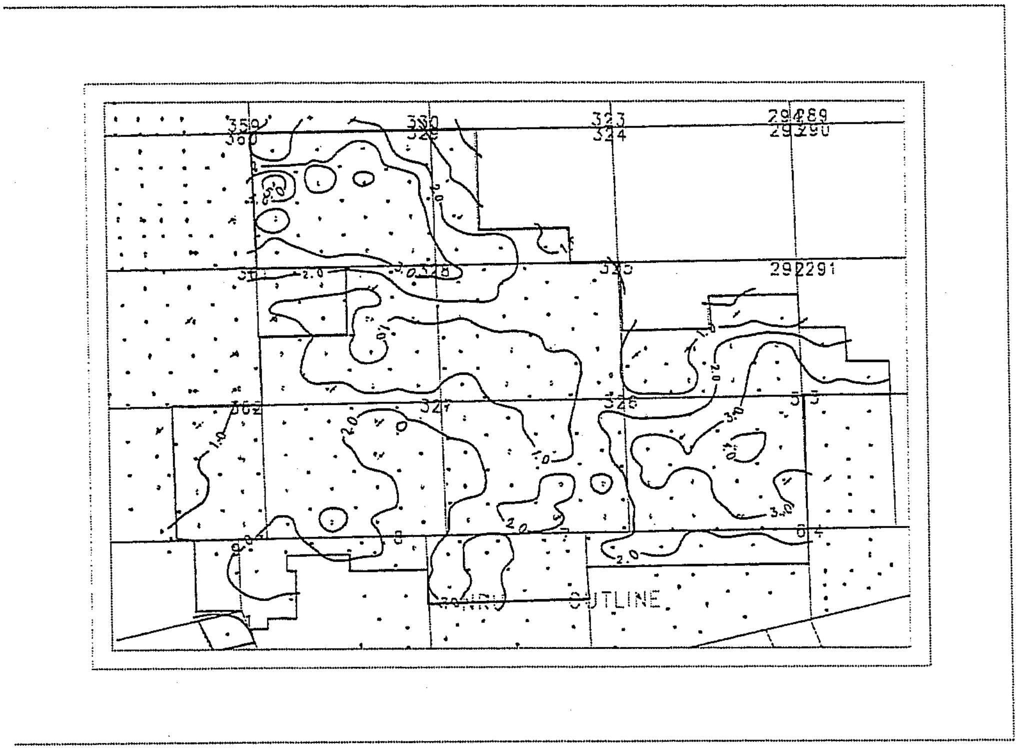

Fig. 9 - NRU - Map of 40-acre well contacted oil-in-place (CI = 1.0 mil. bbls).

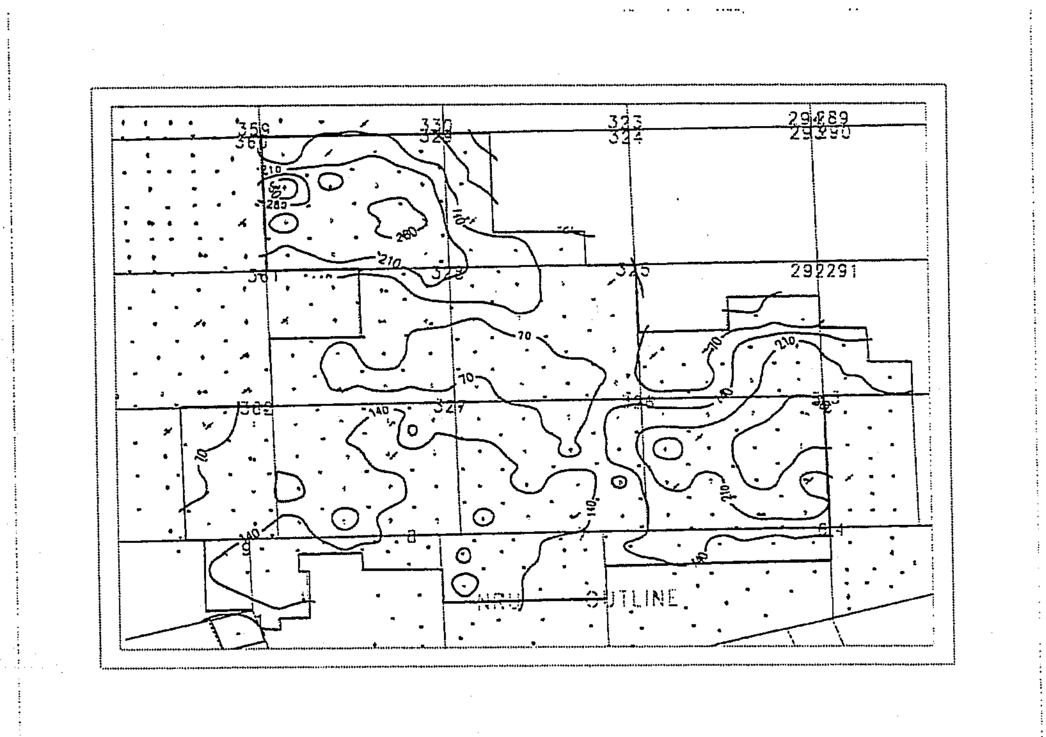

Fig. 10 - NRU - Map of 40-acre well estimated ultimate recovery (CI = 70 thousand bbls).

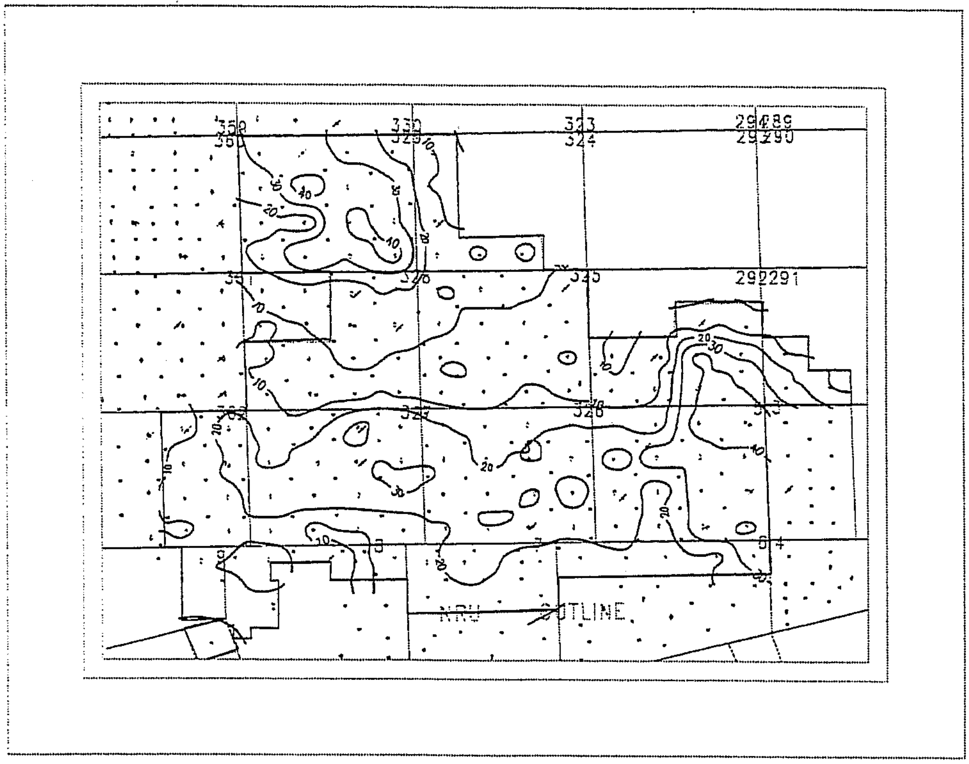

Fig. 11 - NRU - Map of 40-acre well flow capacity, $k_o h$, (CI = 10 md-ft).

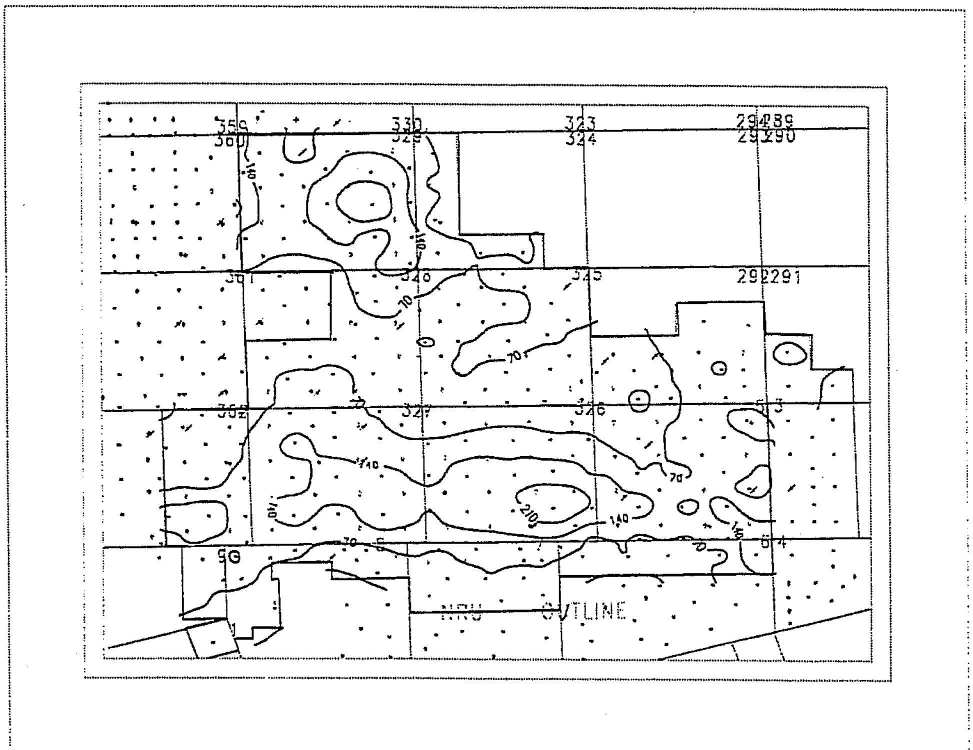

Fig. 12 - NRU - Map of 20-acre well estimated ultimate recovery (CI = 70 thousand bbls).

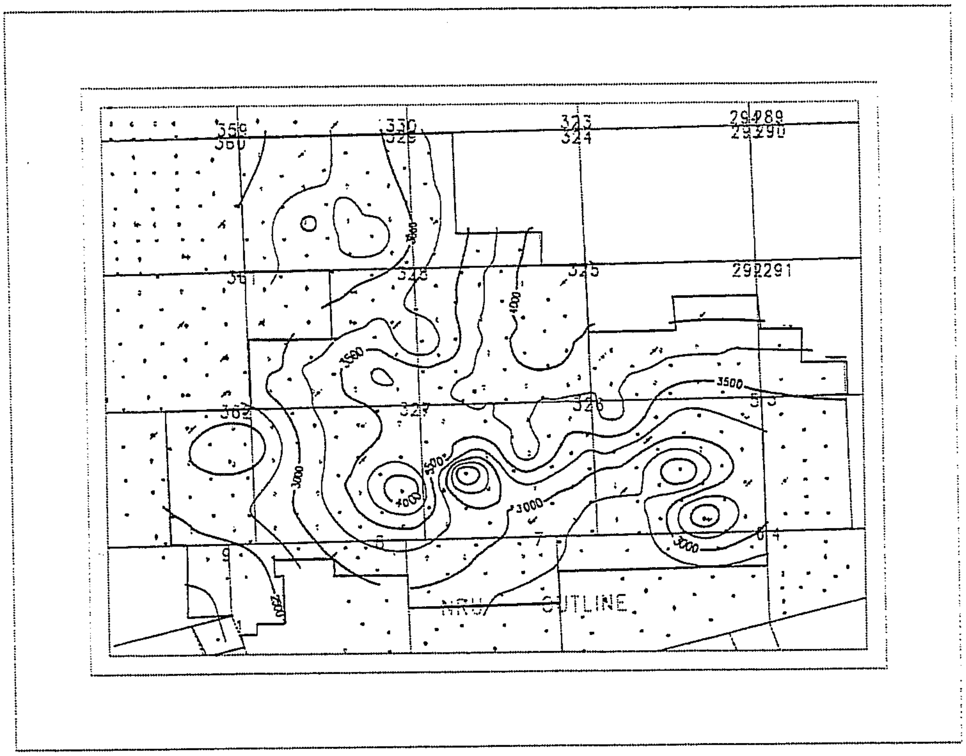

Fig. 13 - NRU - Map of average reservoir pressure, 1995 (CI = 250 psia).

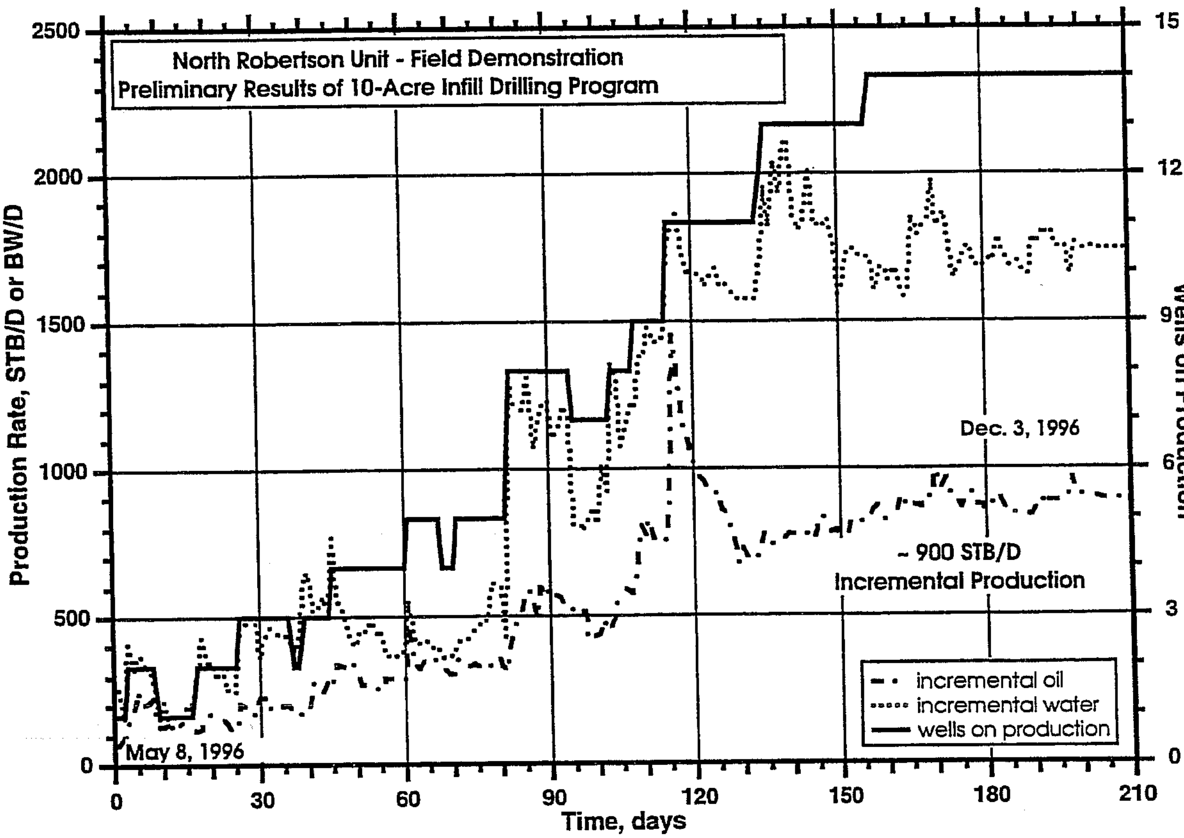

Figure 14 - Incremental production increase due to new 10-acre infill wells.

PfEFFER: THE INTEGRATED ANALYSIS OF WIRELINE LOGS AND RESERVOIR DATA IN A SPREADSHEET ENVIRONMENT

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Kansas Geological Survey, Lawrence, Kansas

INTRODUCTION

As computers evolved from large mainframes to minicomputers to PC microcomputers, so too have the goals of log analysis, as well as the understanding of petrophysical relationships. In the early days of computer processing of logs, exploration for oil and gas was a major activity focused on the location of potential pay zones and the computation of reservoir volumetrics. Today, the emphasis has changed to reservoir management in the more efficient exploitation of existing fields and the recognition of potential by-passed oil and gas. Problems facing producers today also include recognition of underproduced reservoirs, evaluation of fields that have commingled production that limits traditional engineering analysis, and effective utilization of old logs in mature oil and gas fields that challenge conventional log analysis. Increasingly, this task calls on more sophisticated concepts of petroleum geology and their engineering implications than was generally the case in exploration and initial exploitation. In the past, once a reservoir was characterized, this model was tested directly in the field through implementation of a reservoir management option. Today, the option exists to apply a quantitative reservoir characterization to low cost or freeware desktop fluid flow reservoir simulators such as DOE's BOAST3. Testing production scenarios using a simulator helps to forecast the success or failure of a reservoir management option and in turn limits operator risk. This integration ultimately helps to refine strategies to improve oil and gas recovery. Also, modification of reservoir characterization may also be warranted through iterative modeling. An easy to use, cost-effective, and efficient link between reservoir characterization and reservoir simulation has the potential to lower risks and help target optimal strategies for improved oil and gas recovery.

At the same time, the responsibility for log analysis has increasingly shifted from petrophysical specialists to lay geologists or engineers with broad "team" assignments in the major companies. In smaller companies and among independents, log analysis is also only one of many tasks that an employee will be charged to work on. Managers in large companies are showing reluctance to spend large sums of money on hardware or software, particularly when their employees are challenged both to find the time to master overly complex software and to resolve conflicts between hardware and software upgrades. Smaller companies and independents have neither the patience nor the money to expend on such problems. By contrast, spreadsheet software is cheap and runs on cheap machines; most potential users are well advanced on the learning curve from their exposure to spreadsheets in high school and college.

Spreadsheet skills already acquired can be used to extend the capabilities of PfEFFER to new analyses at the wish of the practiced users. Many secretaries have been trained in spreadsheet use and could be trained very easily for log data entry tasks. In summary, the spreadsheet medium provides an environment that can be used readily and productively by a variety of employees.

PfEFFER DESIGN AND OPERATION

PfEFFER (Petrofacies Evaluation of Formations For Engineering Reservoirs) is a Visual Basic "add-in" computer program that can be operated from the Microsoft spreadsheet program EXCEL for the petrofacies analysis and mapping of hydrocarbon reservoirs. The spreadsheet style of computer programming is a powerful means to evaluate and compare potential production zones as a cost-effective, practical tool in the real-time characterization and analysis of both simple and complex reservoirs. The equations and models of PfEFFER are firmly grounded in the models and equations of classic log analysis. The Pickett plot plays a central role in the methodology as a graphical space to map all of these relationships. Spreadsheet database and graphics features allow both rapid interaction and comparative evaluation of multiple interpretations or best case/worst case extremes. The spreadsheet does not itself provide THE answer but allows the user to explore a variety of alternatives very easily. In the case of a straightforward analysis, the user may be satisfied with a single solution. In other cases, the user will be free to generate as many alternative scenarios or best and worst cases as desired. Errors on the logging tool measurements can be accommodated by incorporating simulated error from a spreadsheet random number generator in a series of multiple runs. Sensitivity analysis can also be applied to equation parameters to evaluate their influence on reservoir calculations. In addition, multiple wells are also easily handled collectively, so that the program is used to prepare maps and cross-sections of analysis parameters across hydrocarbon fields. Case studies of petrofacies analysis have been developed for a variety of fields using data supplied by a consortium of supporting companies.

The goals of PfEFFER include the resolution of reservoir parameters that control performance; to characterize subtle reservoir properties important in understanding and modeling hydrocarbon pore volume and fluid flow; the expeditious recognition of bypassed, subtle, and complex oil and gas reservoirs; the systematic differentiation of commingled reservoirs as an aid in reservoir management options to improve recovery; assistance in integrating large amounts of geological and engineering information to improve reservoir modeling and to define appropriate recovery technologies; and the provision of practical tools to assist the geoscientist, engineer, and petroleum operator in making their tasks more efficient and effective.

An electronic spreadsheet program typically organizes its files as a set of worksheets contained within a workbook. For the purposes of log analysis, a useful convention is to equate a workbook with a well, and then stratigraphic or reservoir subdivisions can be allocated to separate worksheets within the well workbook. An oil or gas field would then be represented by a group of workbooks, each matched with a separate well. If an additional workbook is assigned to the field, it can be used to capture all the characteristics associated with the wells and their reservoir subdivisions. Cells in the field workbook can be linked directly with cells in the sheets of the well workbooks. By this process, the field workbook contains all the current log information on the field and will automatically revise its contents if changes are made in any of the well sheets. This capability has enormous advantages in the improvement of log analysis procedures and the presentation of field-wide results. Estimations of log analysis parameters can be made easily on a multi-well basis, rather than a linear sequence with consequent increase in consistency and decrease in uncertainty. Graphic mapping of well data highlights problem wells that can be checked immediately by entering their workbooks. Corrections in the well workbooks will then be carried forward automatically for incorporation in the revised maps. Used in this way, the mapping process becomes a part of the log analysis through the interactive comparison of results from neighboring wells, rather than the consideration of each well in isolation.

An additional cross-section capability allows panels to be constructed of well variability across a field in the dimension of depth. Log variables or reservoir attributes are color-coded as spreadsheet columns and hung on a user-selected datum. The cross-section panel provides an immediate perspective on reservoir connectivity and conformance, and provides a useful medium for flow-unit assignation. The panel also provides a means to integrate conventional log analysis with a conceptual geological model such as a sequence stratigraphic interpretation of a reservoir. This direct link between log analysis and spatial distribution makes it possible to iterate to an optimal solution of petrophysical and geological constructs ensuring a more constrained and accurate reservoir model.

Reservoir simulation requires careful reservoir characterization, acquisition and organization of reservoir parameters, and grid design. PfEFFER assists in this procedure by providing tools to convert well coordinates to those used by the simulator, establish the plot file for each layer and each parameter, design grid spacing, generate the grids, and locate the wells in the grid domain for ease in editing and establishing the simulation input file.

The ability to move rapidly between wells and reservoir units therefore makes it possible to run a "mosaic" style of log analysis rather than a conventional linear approach. Not so long ago, log analysis was a highly labor-intensive task in which much of the analyst's time was spent in calculation rather than in interpretation. Procedures were generally organized as a linear sequence of steps, so that results could be obtained efficiently and in a reasonable time. By contrast, the web of links between well log files within a field allows the analyst to choose to follow one of many possible pathways through a mosaic of steps that appears best suited to the problem at hand.

In summary, PfEFFER was developed for a number of reasons:
(1) To provide cost-effective log analysis software as a Visual Basic add-in that could be run on a PC using EXCEL, a spreadsheet program that is used widely throughout the energy industry;
(2) To allow data to be accessed easily, either from digital LAS files or from manual input;
(3)To use the numerical processing and graphics capabilities of the spreadsheet medium to make classical log analysis calculations while simultaneously displaying crossplots for pattern recognition;
(4) To augment the traditional log analysis methods with techniques that incorporate estimations of pore size, permeability, and mineralogy in extensions of the Pickett plot (the "Super Pickett plot");
(5) To design the program as a tool to improve the use of log analysis in characterizing reservoirs, detecting heterogeneities, and deciphering subtle pay zones;
(6) To provide a mapping capability, so that spatial variations in reservoir properties could be mapped between wells as 2-D maps or 3-D surfaces;.;
(7) To provide a cross-section tool that displays spreadsheet information, to aid in evaluating reservoir correlation, continuity, conformance, and flow-unit assignment;
(8) To emphasize user-friendliness so that the log analyst, geologist, or reservoir engineer who is a casual computer user can rapidly become a proficient user;
(9) To provide a design base for PfEFFER-Pro, that includes linkage to DOE's BOAST III reservoir simulator, a simple GIS capability, and the generation of 3-D "pseudo-seismic" volumes.

Software development was undertaken with the financial, data, and beta testing support of BDM-Oklahoma, the Kansas Technology Enterprise Corporation (KTEC), independent and twelve oil and gas companies who operate in Kansas. The first version of the program, PfEFFER 1.0 was completed in December, 1995 and PfEFFER 1.1 is now on sale from the KGS as both PC and Macintosh software. The product has already been extremely well received by industry clients and is marketed through World Wide Web page. Current requirements of this software include: IBM-compatible personal computers (386 or better) with at least 4 megabytes of RAM, a hard disk, a graphics display compatible with Microsoft Windows version 3.1 or later, MS-DOS version 3.1 or later, Microsoft Windows version 3.1 or later in standard or enhanced mode, and mouse. Power Macintosh requires at least 4 megabytes of RAM, hard disk, Macintosh System 7.0 or later in order to run the program efficiently. All PfEFFER versions are in Visual Basic code using syntax included with EXCEL version 5.0c for the PfEFFER1 series and EXCEL 97 for the PfEFFER2 series.

SOURCES OF INFORMATION FOR PfEFFER

Demonstration version of PfEFFER software is available at North Midcontinent PTTC office located at Kurata Thermodynamics Laboratory on Campus West (see map). North Midcontinent PTTC office mailing address is C/O Energy Research Center, University of Kansas, 1930 Constant Avenue, Lawrence, Kansas 66047-3724, Ph: (785) 864-7398, Fax: (785) 864-7399. Home page web address for the North Midcontinent PTTC office is
http://crude 2.kgs.ukans.edu/ERC/pttcHome.html.
Home page web address for Energy Research Center is
http://crude2.kgs.ukans.edu/ERC/index.html.

The software can be purchased at the Publication Sales office at the Kansas Geological Survey, University of Kansas, 1930 Constant Ave., Lawrence, KS 66047-3726 (see map), phone 785-864-3965, fax 785-864-5317,
http://www.kgs.ukans.edu/. PfEFFER's home page web address is
http://crude2.kgs.ukans.edu/PRS/software/pfeffer1.html and includes an order form located at http://crude
2.kgs.ukans.edu/PRS/software/orderForm.gif. An additional description of PfEFFER is included in the Survey's online catalog at the web address
http://crude2.kgs.ukans.edu/Datasale/catalog97/software.html
Direct inquiries about PfEFFER can be requested via e-mail at
PfEFFER@kgs.ukans.edu.

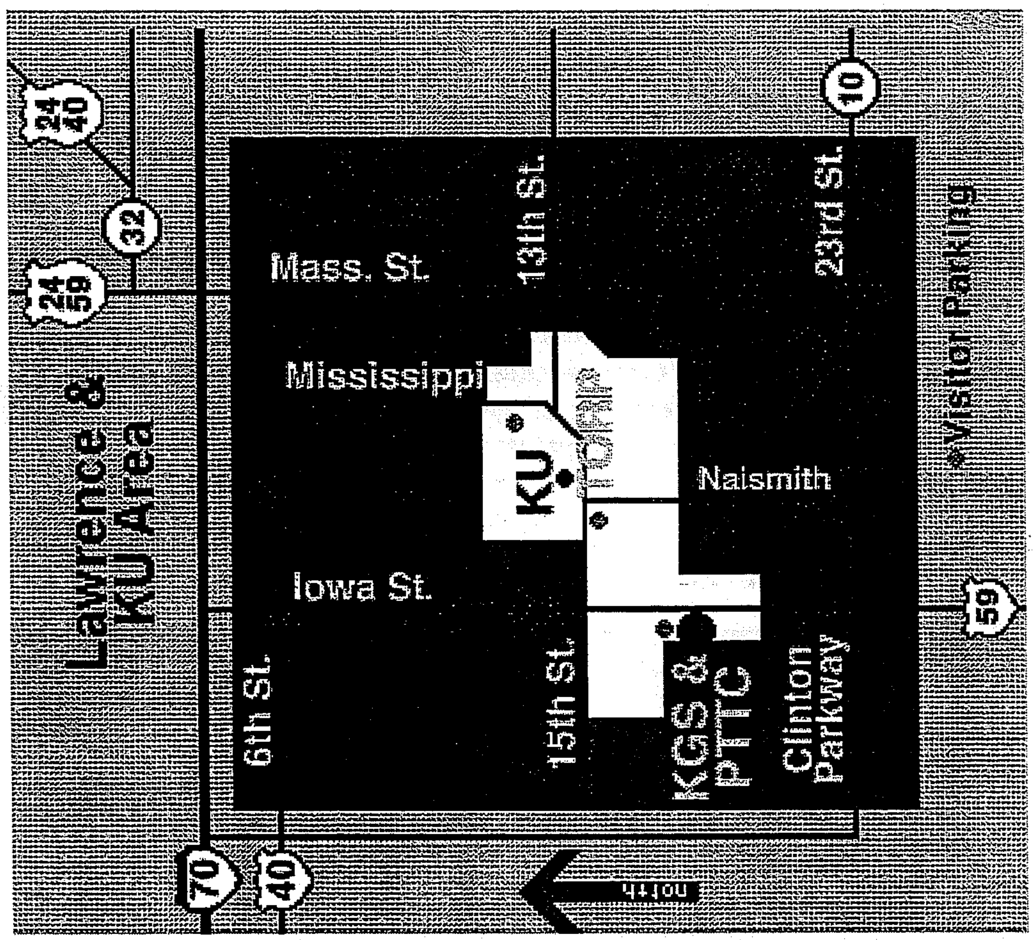
PUBLICATIONS

Doveton, J.H., Guy, W.J., Watney, W. L., Bohling, G.C., Ullah, S., and Adkins-Heljeson, D., 1996, Log analysis of petrofacies and flow-units with microcomputer spreadsheet software: 1995 AAPG Mid-Continent Meeting.Transactions, p.224-233.

Doveton, J.H., Guy, W.J., Watney, W.L., Bohling, G.C., Ullah, S., Adkins-Heljeson, D., 1995, PfEFFER 1.0 manual: Kansas Geological Survey, Open-file Report #95-29, 117 p.

Doveton, John H., Watney, W. Lynn and Guy, Willard J., 1997, Petrofacies Analysis - the petrophysical tool for geologic/engineering reservoir characterization : Fourth International Reservoir Characterization Conference Proceedings, p. 99-114.

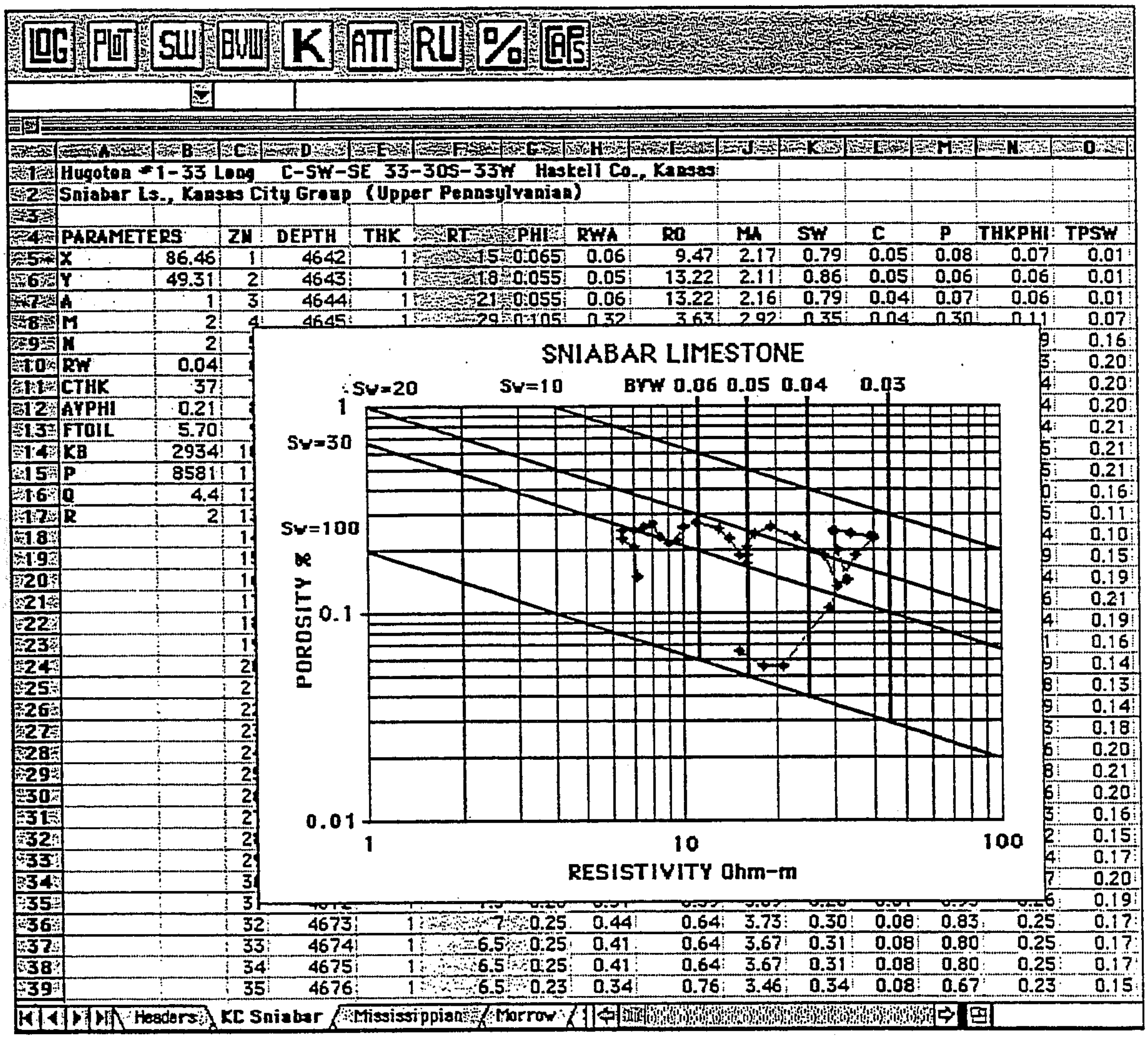
Doveton, John H., Guy, Willard J., and Watney, W. Lynn, 1997, PfEFFER - Log Analysis spreadsheet solutions for reservoir engineering and petroleum geology: Proceedings of the 12th TORP Conference, p. 85 - 90.



Lawrence &
KU Area
24
40
24
59
32
70
40
10
59
Mass. St.
Mississippi
Iowa St.
6th St.
13th St.
15th St.
23rd St.
KU
Naismith
KGS &
PTTC
Clinton
Parkway
Visitor Parking
north

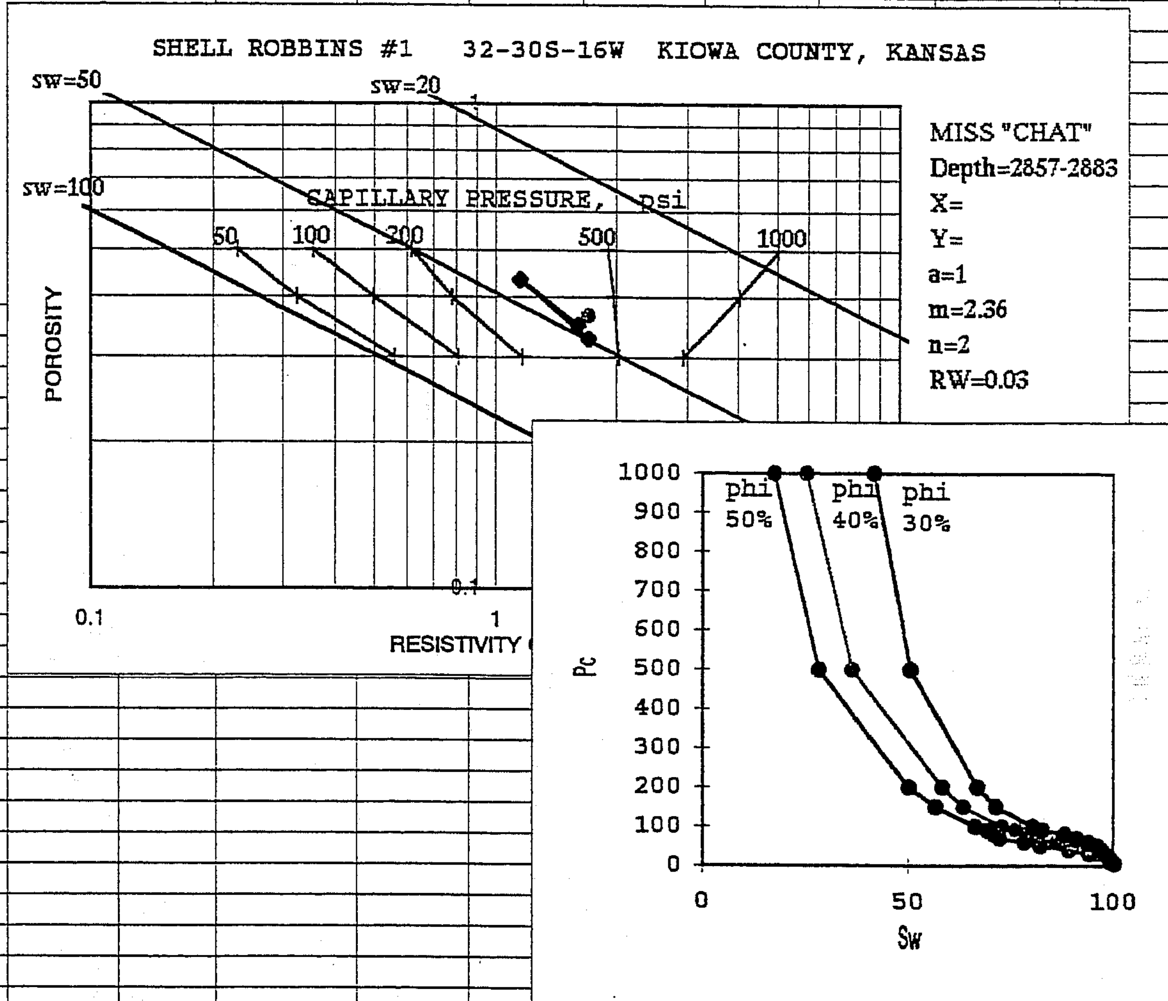
TIMELINE	1970 — 1980 — 1990 →
GOALS	EXPLORATION · EXPLOITATION
TASKS	VOLUMETRICS · PRODUCTIVITY
MACHINES	MAINFRAMES · MINIS · MICROS
MODE	BATCH · INTERACTIVE · SPREADSHEET
LOG USER	SPECIALIST · GENERALIST

Schematic history of changes in oil and gas industry objectives and concurrent styles in computer hardware and software.



PfEFFER: The spreadsheet environment

SHELL ROBBINS #1		32-30S-16W	KIOWA COUNTY, KANSAS							
MISS "CHAT"										
PARAMETERS		ZN	DEPTH	THK	RT	PHI	RWA	RO	MA	SW
X		1	2857	5	1.7	0.366	0.16	0.32	4.02	0.43
Y		2	2863	10	1.6	0.35	0.13	0.36	3.79	0.47
A	1	3	2873	10	1.15	0.434	0.16	0.22	4.37	0.43
M	2.36	4	2883	10	1.7	0.328	0.12	0.42	3.62	0.49
N										
RW										
CTHK										
AVPHI										
FTOIL										
KB										
P										
Q										
R										



PfEFFER: Reconciliation of logs with capillary pressure measurements

UMAA	RHOMAA					Dolomite	Quartz	Calcite
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8.89305	2.86657	UMAA	9	4.79	13.77	0.85253	0.09024	0.05723
9.26444	2.85985	RHOMAA	2.9	2.65	2.71	0.81106	0.07091	0.11803
10.4088	2.86815	UNITY	1	1	1	0.81403	-0.0581	0.24407
13.2097	2.82325					0.5273	-0.2177	0.69039
14.7777	2.81365	INVERSE MATRIX:				0.43681	-0.3442	0.90743
16.3979	2.80871		-0.0301	4.50713	-11.8	0.36574	-0.4869	1.12118
12.7556	2.81756		-0.0954	-2.3941	7.80114	0.51534	-0.1608	0.64543
9.47663	2.81593		0.12548	-2.113	4.99849	0.60673	0.15582	0.23745
[illegible]	[illegible]					0.65351	0.26457	0.08193
								18
								92
								68
								34
								32
								08
								53
								59
								25
								45
								85
								92
								61
								78
								59
								11
8.04109	2.7436							15
8.09097	2.72971							77
8.01828	2.72414							42
7.81938	2.70427							45
7.77197	2.70883							86
7.95345	2.70849							35
8.27703	2.69816							77
7.81599	2.6904							33
7.57205	2.70212							94
7.43055	2.7123							68
8.08255	2.70808							42
8.43309	2.7368							72
8.60761	2.74872							41
8.51206	2.76495							14
8.3562	2.75895							25
8.86456	2.76659							49
9.80781	2.76584							85
10.6253	2.76819							45
10.031	2.76233							28
9.38751	2.77044							24
9.44747	2.79072							07
10.1186	2.82256							99
9.83568	2.84619							56
9.44374	2.85837					0.799	0.05735	0.14365
9.11059	2.86139					0.82265	0.08189	0.09546
9.54774	2.85527					0.78189	0.05486	0.16325
9.40877	2.82639					0.65592	0.13725	0.20683
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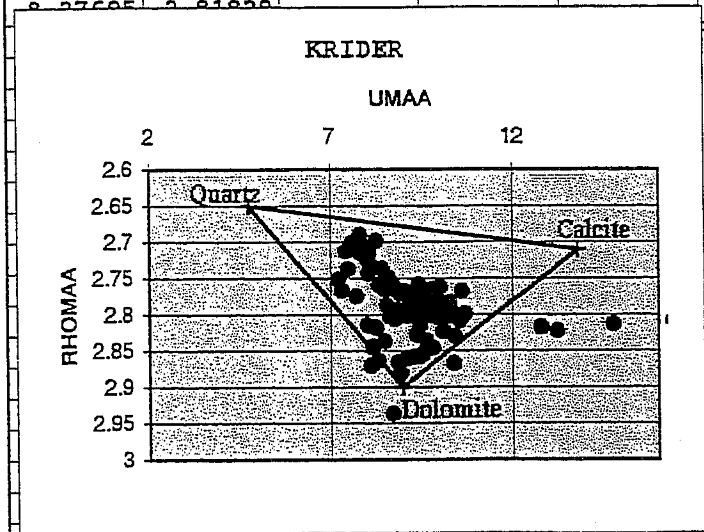
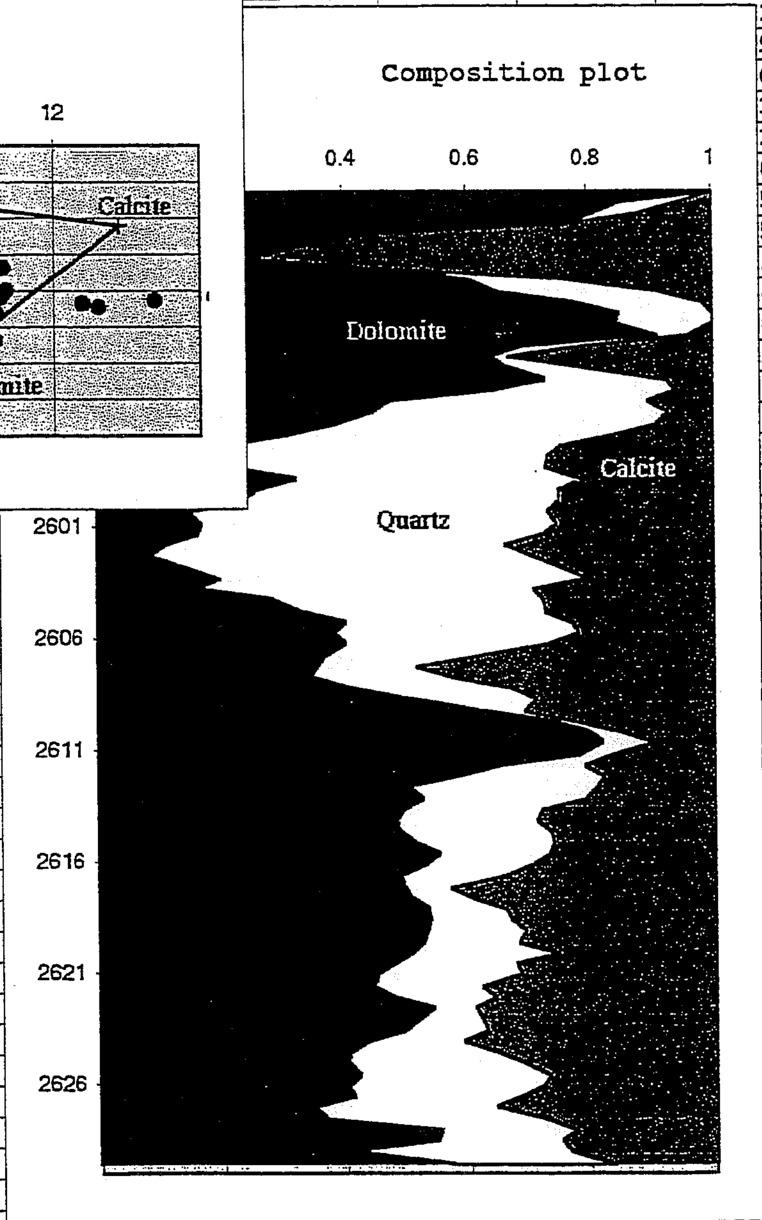
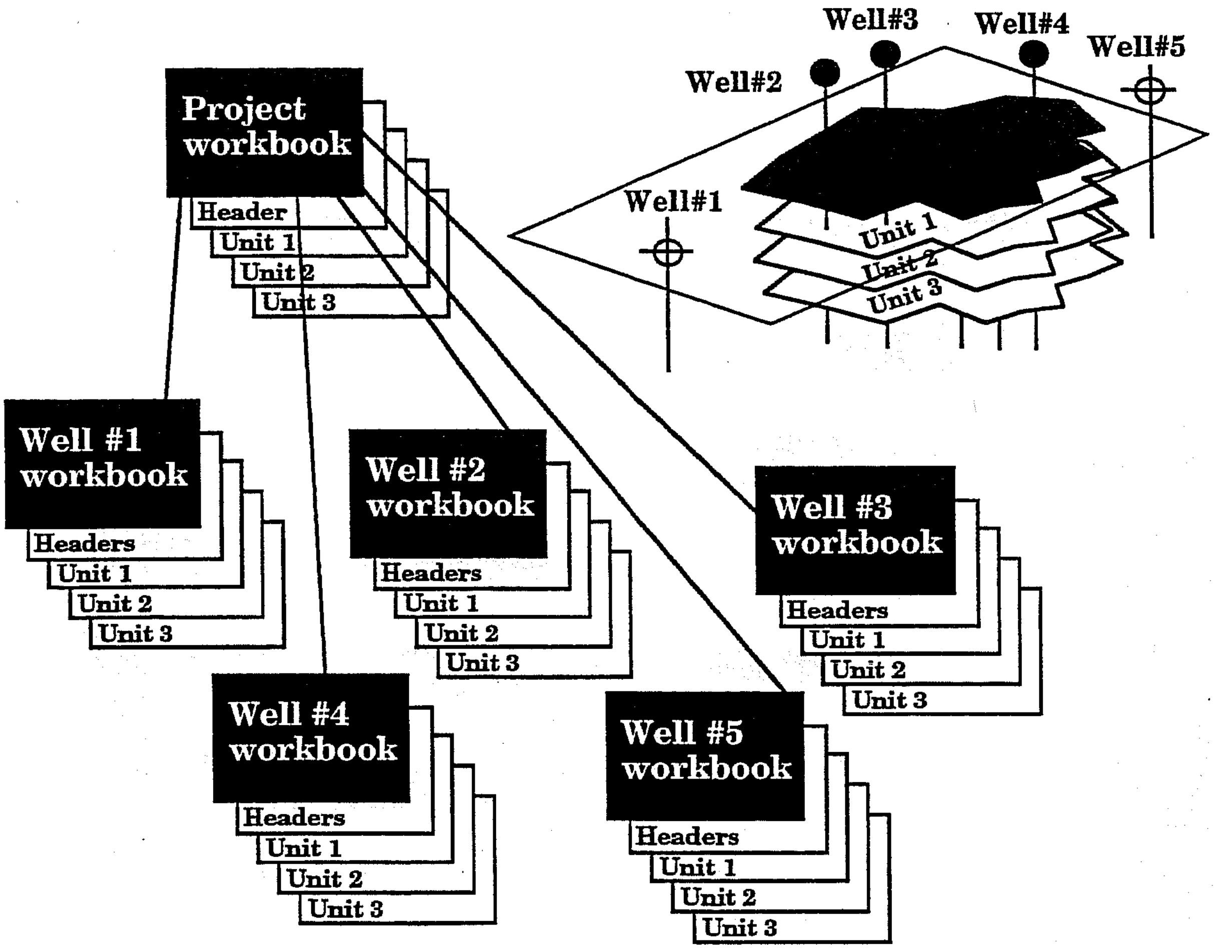
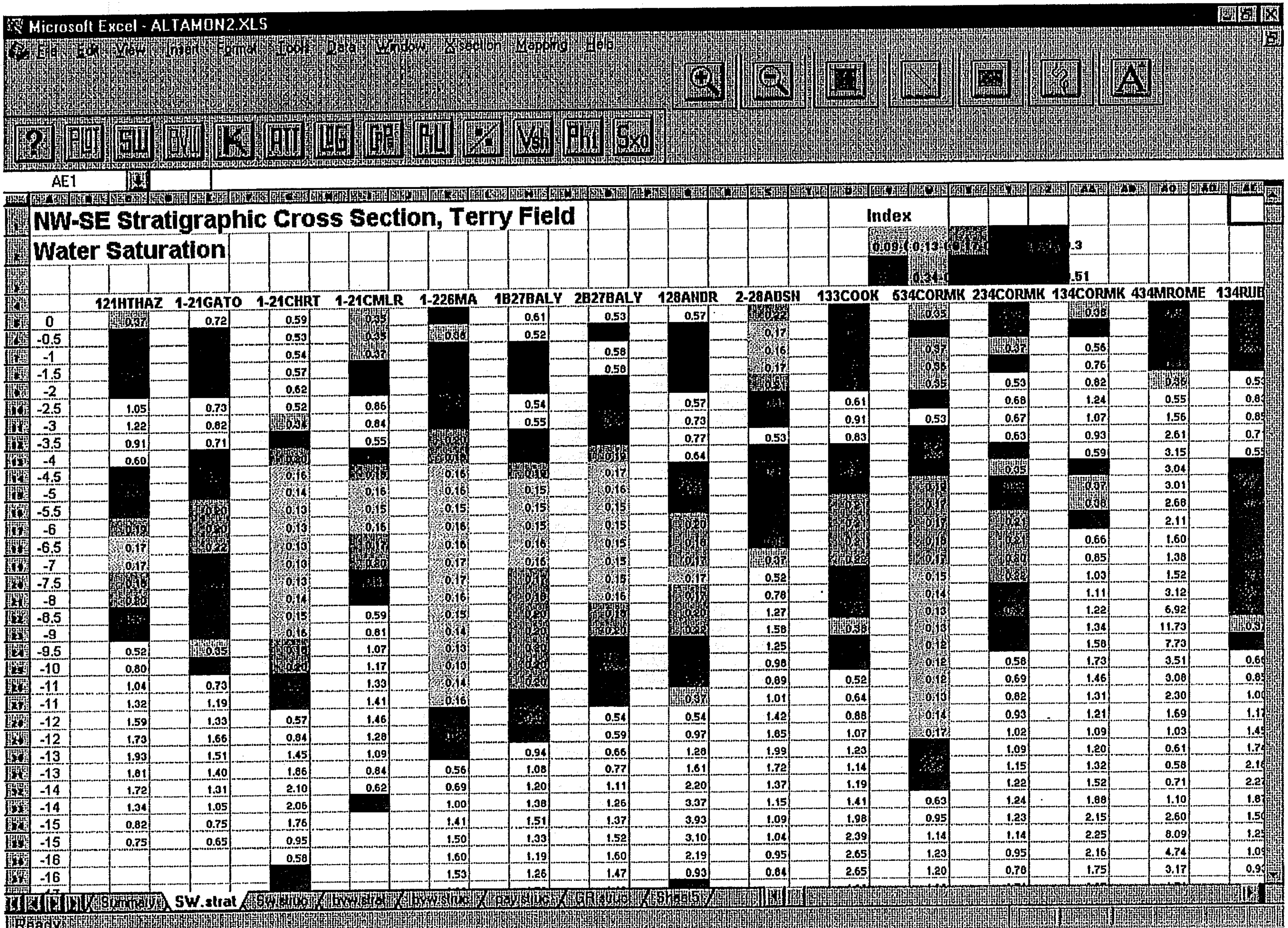




PfEFFER: Compositional analysis from logs



Field representation by a PfEFFER file hierarchy

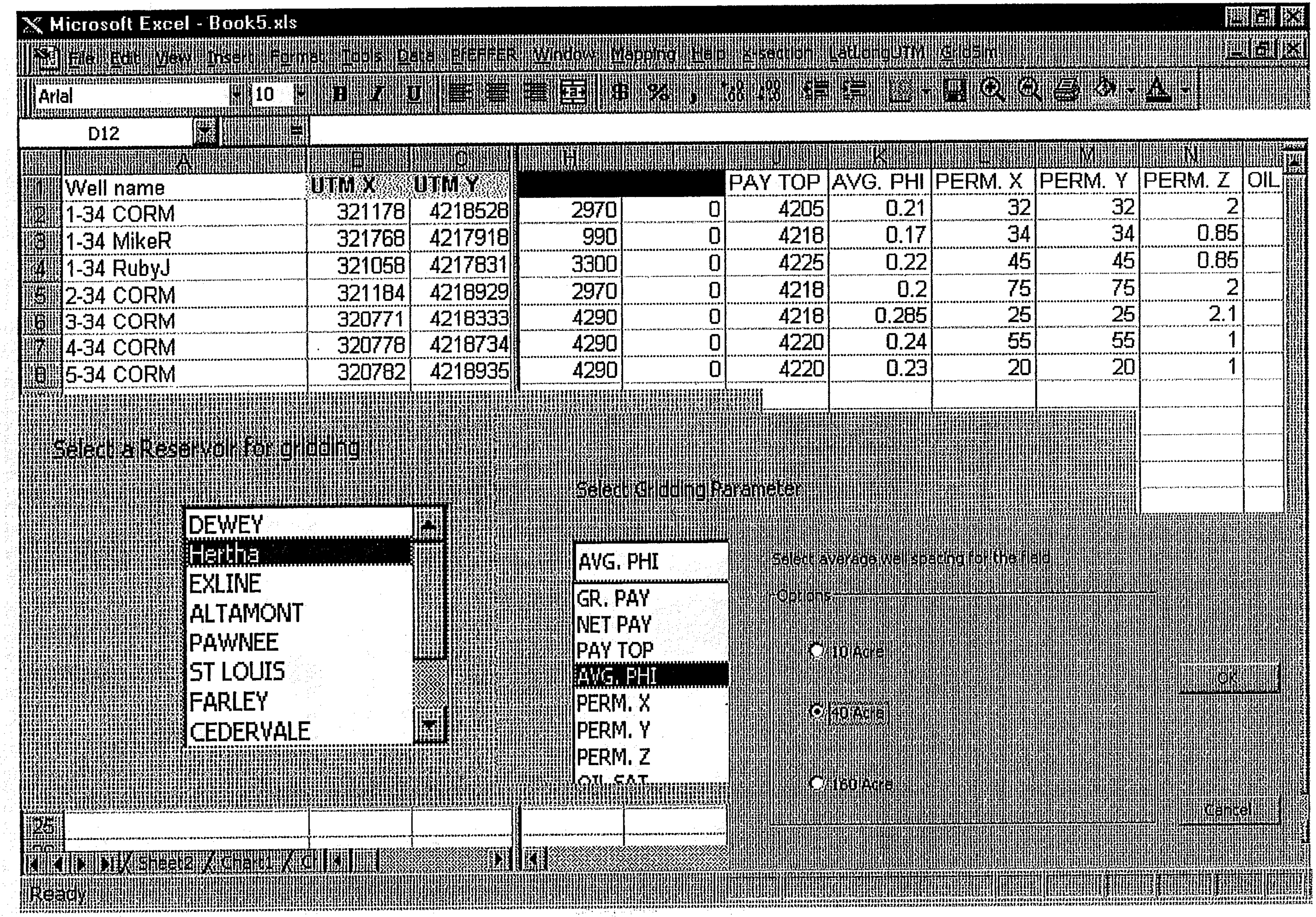


NW-SE Stratigraphic Cross Section, Terry Field

Water Saturation

Index: 0.09 0.13 0.17 .3 / 0.34 .51

	121HTHAZ	1-21GATO	1-21CHRT	1-21CMLR	1-226MA	1B27BALY	2B27BALY	128ANDR	2-28ADSN	133COOK	634CORMK	234CORMK	134CORMK	434MROME	134RUB
0	0.37	0.72	0.59	0.35		0.61	0.53	0.57	0.22		0.35		0.38		
-0.5			0.53	0.35	0.36	0.52			0.17						
-1			0.54	0.37			0.58		0.16		0.37	0.37	0.56		
-1.5			0.57				0.58		0.17		0.36		0.76		
-2			0.62						0.51		0.35	0.53	0.82	0.36	0.53
-2.5	1.05	0.73	0.52	0.86		0.54		0.57		0.61		0.68	1.24	0.55	0.83
-3	1.22	0.82	0.34	0.84		0.55		0.73		0.91	0.53	0.67	1.07	1.56	0.85
-3.5	0.91	0.71		0.55	0.20			0.77	0.53	0.83		0.63	0.93	2.61	0.71
-4	0.60		0.20		0.18		0.19	0.64					0.59	3.15	0.55
-4.5			0.16	0.18	0.16	0.19	0.17					0.35		3.04	
-5			0.14	0.16	0.16	0.15	0.16				0.19		0.37	3.01	
-5.5		0.20	0.13	0.15	0.15	0.15	0.15			0.21	0.17		0.38	2.68	
-6	0.19	0.20	0.13	0.16	0.16	0.15	0.15	0.20		0.21	0.17	0.21		2.11	
-6.5	0.17	0.22	0.10	0.17	0.16	0.16	0.15	0.16		0.21	0.18	0.21	0.66	1.60	
-7	0.17		0.10	0.20	0.17	0.16	0.15	0.13	0.37	0.22	[illegible]	0.20	0.85	1.38	
-7.5	0.18		0.13		0.17	0.17	0.15	0.17	0.52		0.15	0.22	1.03	1.52	
-8	0.20		0.14		0.16	0.18	0.16	0.17	0.78		0.14		1.11	3.12	
-8.5			0.15	0.59	0.15	0.20	0.19	0.20	1.27		0.13		1.22	6.92	
-9			0.16	0.81	0.14	0.20	0.20	0.22	1.58	0.38	0.13		1.34	11.73	0.37
-9.5	0.52	0.35	0.18	1.07	0.13	0.30			1.25		0.12		1.58	7.73	
-10	0.80		0.20	1.17	0.10	0.20			0.98		0.12	0.58	1.73	3.51	0.66
-11	1.04	0.73		1.33	0.14	0.20			0.89	0.52	0.12	0.69	1.46	3.08	0.85
-11	1.32	1.19		1.41	0.16			0.37	1.01	0.64	0.10	0.82	1.31	2.30	1.00
-12	1.59	1.33	0.57	1.46			0.54	0.54	1.42	0.88	0.14	0.93	1.21	1.69	1.17
-12	1.73	1.66	0.84	1.28			0.59	0.97	1.85	1.07	0.17	1.02	1.09	1.03	1.49
-13	1.93	1.51	1.45	1.09		0.94	0.66	1.28	1.99	1.23		1.09	1.20	0.61	1.74
-13	1.81	1.40	1.86	0.84	0.56	1.08	0.77	1.61	1.72	1.14		1.15	1.32	0.58	2.16
-14	1.72	1.31	2.10	0.62	0.69	1.20	1.11	2.20	1.37	1.19		1.22	1.52	0.71	2.27
-14	1.34	1.05	2.06		1.00	1.38	1.26	3.37	1.15	1.41	0.63	1.24	1.88	1.10	1.87
-15	0.82	0.75	1.76		1.41	1.51	1.37	3.93	1.09	1.98	0.95	1.23	2.15	2.60	1.50
-15	0.75	0.65	0.95		1.50	1.33	1.52	3.10	1.04	2.39	1.14	1.14	2.25	8.09	1.25
-16			0.58		1.60	1.19	1.60	2.19	0.95	2.65	1.23	0.95	2.16	4.74	1.09
-16					1.53	1.26	1.47	0.93	0.84	2.65	1.20	0.78	1.75	3.17	0.93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Well name UTM X UTM Y PAY TOP AVG. PHI PERM. X PERM. Y PERM. Z OIL
1-34 CORM 321178 4218528 2970 0 4205 0.21 32 32 2
1-34 MikeR 321768 4217918 990 0 4218 0.17 34 34 0.85
1-34 RubyJ 321058 4217831 3300 0 4225 0.22 45 45 0.85
2-34 CORM 321184 4218929 2970 0 4218 0.2 75 75 2
3-34 CORM 320771 4218333 4290 0 4218 0.285 25 25 2.1
4-34 CORM 320778 4218734 4290 0 4220 0.24 55 55 1
5-34 CORM 320782 4218935 4290 0 4220 0.23 20 20 1
Select a Reservoir for gridding
DEWEY
Hertha
EXLINE
ALTAMONT
PAWNEE
ST LOUIS
FARLEY
CEDERVALE
Select Gridding Parameter
AVG. PHI
GR. PAY
NET PAY
PAY TOP
AVG. PHI
PERM. X
PERM. Y
PERM. Z
Select average well spacing for the field
Options
10 Acre
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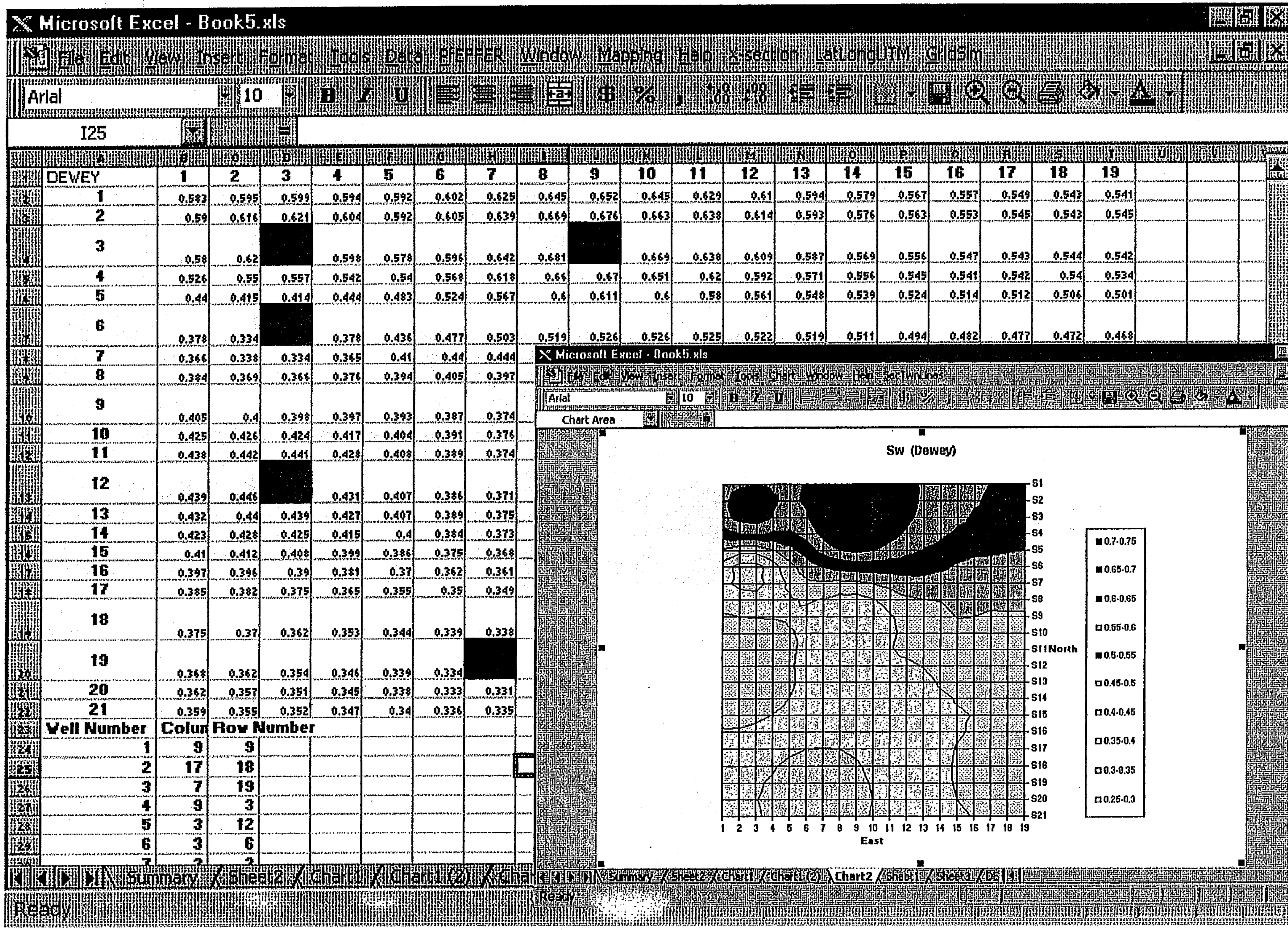
160 Acre
OK
Cancel
Sheet2
Chart1
Ready



DEWEY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
1	0.583	0.595	0.599	0.594	0.592	0.602	0.625	0.645	0.652	0.645	0.629	0.61	0.594	0.579	0.567	0.557	0.549	0.543	0.541
2	0.59	0.616	0.621	0.604	0.592	0.605	0.639	0.669	0.676	0.663	0.638	0.614	0.593	0.576	0.563	0.553	0.545	0.543	0.545
3	0.58	0.62	[redacted]	0.598	0.578	0.596	0.642	0.681	[redacted]	0.669	0.638	0.609	0.587	0.569	0.556	0.547	0.543	0.544	0.542
4	0.526	0.55	0.557	0.542	0.54	0.568	0.618	0.66	0.67	0.651	0.62	0.592	0.571	0.556	0.545	0.541	0.542	0.54	0.534
5	0.44	0.415	0.414	0.444	0.483	0.524	0.567	0.6	0.611	0.6	0.58	0.561	0.548	0.539	0.524	0.514	0.512	0.506	0.501
6	0.378	0.334	[redacted]	0.378	0.436	0.477	0.503	0.519	0.526	0.526	0.525	0.522	0.519	0.511	0.494	0.482	0.477	0.472	0.468
7	0.366	0.338	0.334	0.365	0.41	0.44	0.444												
8	0.384	0.369	0.366	0.376	0.394	0.405	0.397												
9	0.405	0.4	0.398	0.397	0.393	0.387	0.374												
10	0.425	0.426	0.424	0.417	0.404	0.391	0.376												
11	0.438	0.442	0.441	0.428	0.408	0.389	0.374												
12	0.439	0.446	[redacted]	0.431	0.407	0.386	0.371												
13	0.432	0.44	0.439	0.427	0.407	0.389	0.375												
14	0.423	0.428	0.425	0.415	0.4	0.384	0.373												
15	0.41	0.412	0.408	0.399	0.386	0.375	0.368												
16	0.397	0.396	0.39	0.381	0.37	0.362	0.361												
17	0.385	0.382	0.375	0.365	0.355	0.35	0.349												
18	0.375	0.37	0.362	0.353	0.344	0.339	0.338												
19	0.368	0.362	0.354	0.346	0.339	0.334	[redacted]												
20	0.362	0.357	0.351	0.345	0.338	0.333	0.331												
21	0.359	0.355	0.352	0.347	0.34	0.336	0.335												

Well Number	Colun	Row Number
1	9	9
2	17	18
3	7	19
4	9	3
5	3	12
6	3	6
7	2	2

ACOUSTIC LOGGING TO DETECT HYDROCARBONS THROUGH CASING - DOE CLASS III WILMINGTON WATERFLOOD PROJECT

Daniel Moos†

Theoretical relationships, confirmed by laboratory and field data, suggest that hydrocarbon-bearing rocks in situ can be differentiated from rocks containing brines using sonic velocity measurements. A project to test this technique has been undertaken in the Wilmington Field, California, with co-funding from the Department of Energy (DOE cooperative agreement no. DE-FC22-95BC14934). This paper summarizes the principal results and the experience gained during the DOE project.

As part of this work dipole and monopole acoustic data were obtained in a number of wells in the field. In addition, laboratory measurements of the physical properties of core samples were carried out. Rock-log models for the relationships between porosity and velocity and between hydrocarbon saturation and compressional and shear-wave seismic velocity were developed.

The principal results were as follows:

- It was extremely difficult to obtain reliable dipole logs through the old, cased wells logged in the Wilmington field, some of which were drilled in the 1940's. Data was successfully acquired in newer (less than 20 years old) wells.
- Where data were obtained, sands with producible hydrocarbons could be discriminated from those which were watered out.
- Shear-wave seismic velocity could be used to measure porosity using a theoretical relationship appropriate for unconsolidated materials.
- Models developed for this work were applied to acoustic data recorded through casing from a field in South America, and successfully detected previously untested hydrocarbons. In addition, the logs revealed one possible cause of sharply curtailed production from previously productive intervals - those intervals which were initially revealed to contain liquid hydrocarbons are now revealed to contain free gas.

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- Porosity measured using neutron activation logs recorded in one well in the Wilmington field agreed with the porosity derived from the shear-wave (dipole) acoustic data.

As a result of this work it is clear that acoustic methods are reliable means of detecting bypassed oil. These are appropriate for application within cased holes in clastic reservoirs, even where competing technologies (for example, neutron activation logging) cannot be used. However, careful consideration of reservoir rock properties should be made prior to attempting to log target holes, to determine if the data can be acquired.

Published papers / expanded abstracts:

Moos, D., S. Hara, C. Phillips, A. Hooks, and K. Tagbor, 1995. Field test of acoustic logs for measuring porosity and oil saturation in a mature waterflood in the Wilmington Field, CA, Proc. SPE Western Regional Meeting, March 8-10, 1995, pp. 395-408.

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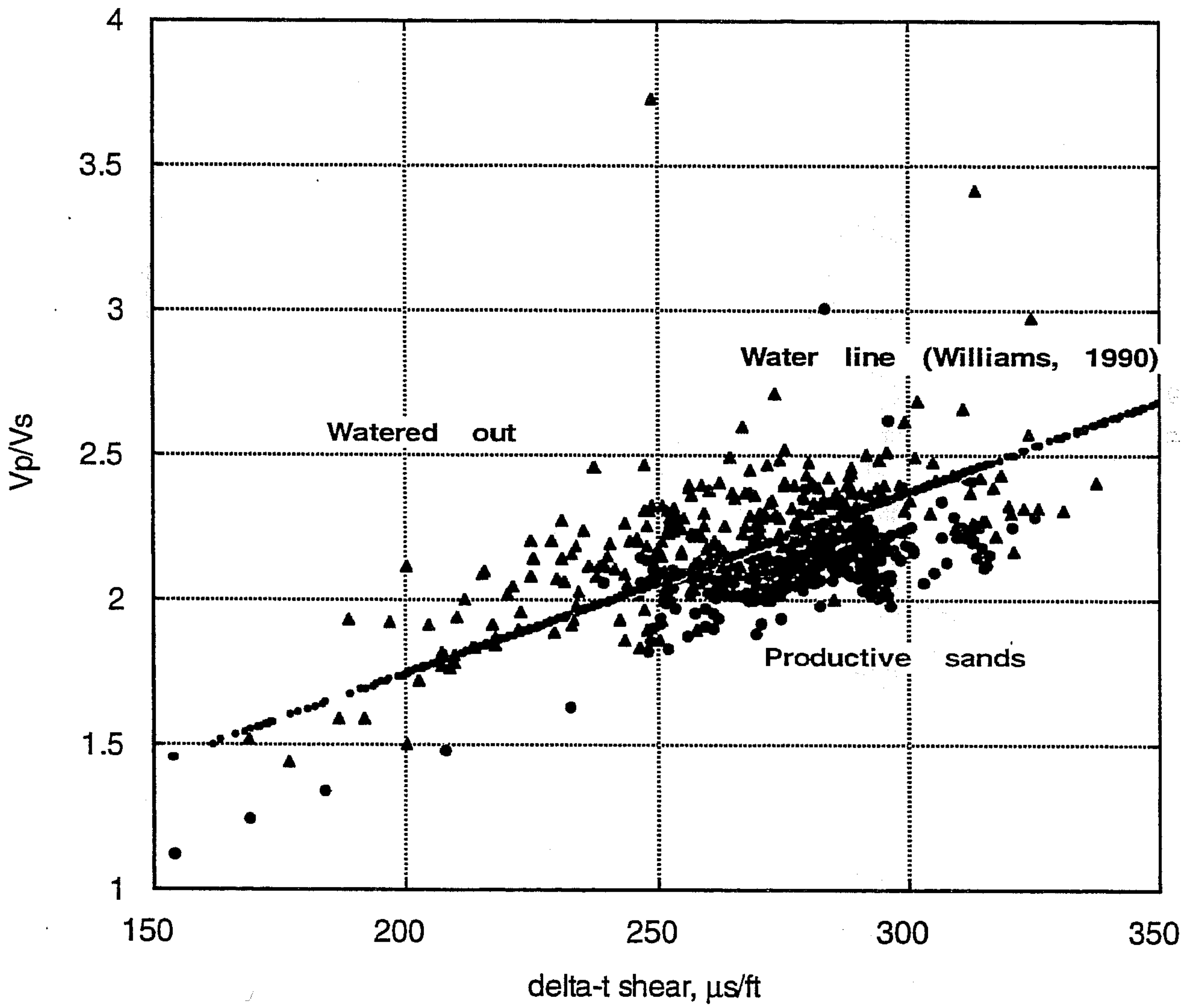
Moos, D., J. Dvorkin, and A. Hooks, 1997. Application of Theoretically Derived Rock Physics Relationships for Clastic Rocks to Log Data - Example from the Wilmington Field, CA, Geophys. Res. Lett. 24(3), pp. 329-332.

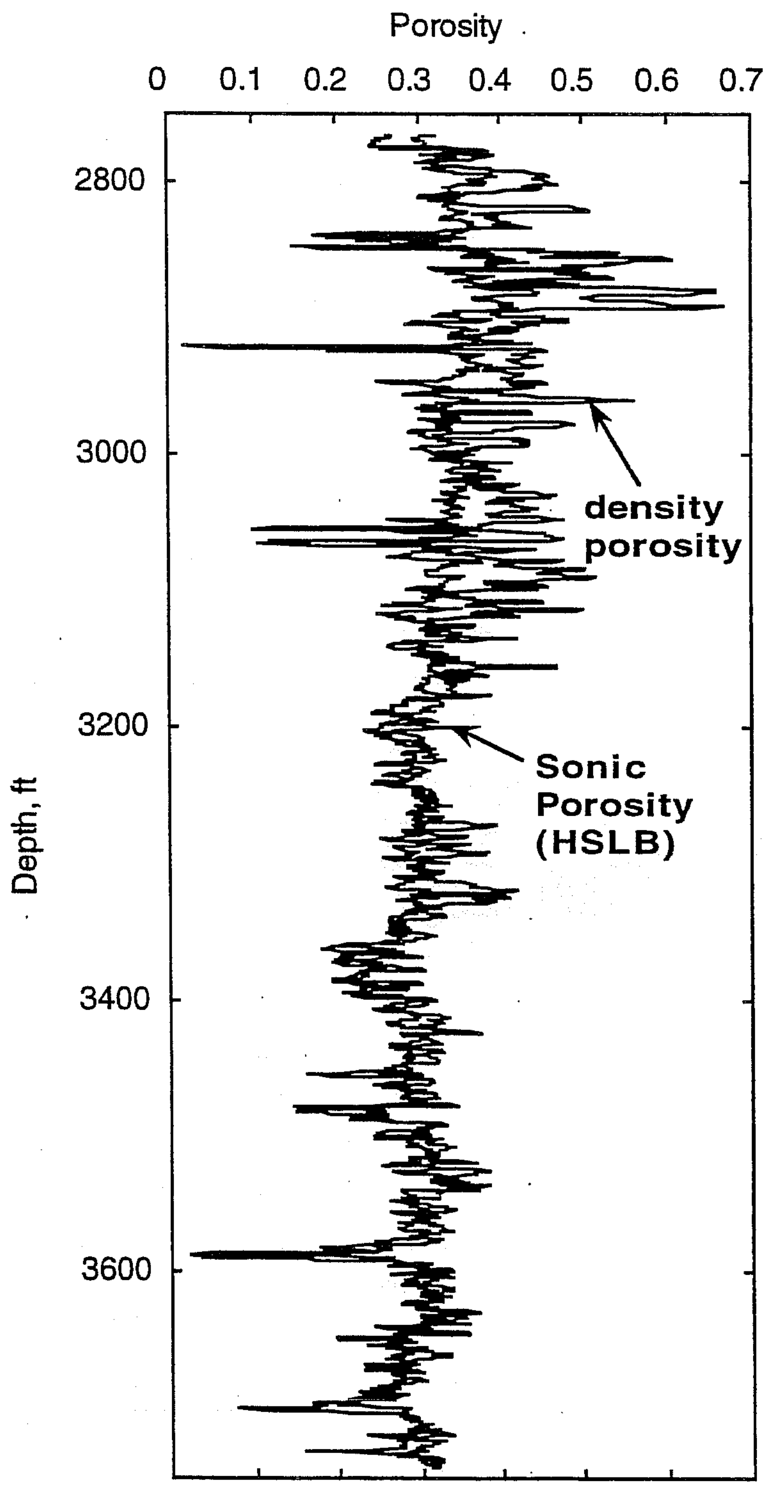
Chang, C., D. Moos, M. D. Zoback, 1997. Anelasticity and dispersion in dry unconsolidated sands, Int. J. Rock Mech. & Min. Sci. 34:3-4, Paper No. 048.

Saturation from Sonic Logging

- •Sonic data can be acquired through casing
- •Can provide simultaneous porosity determination

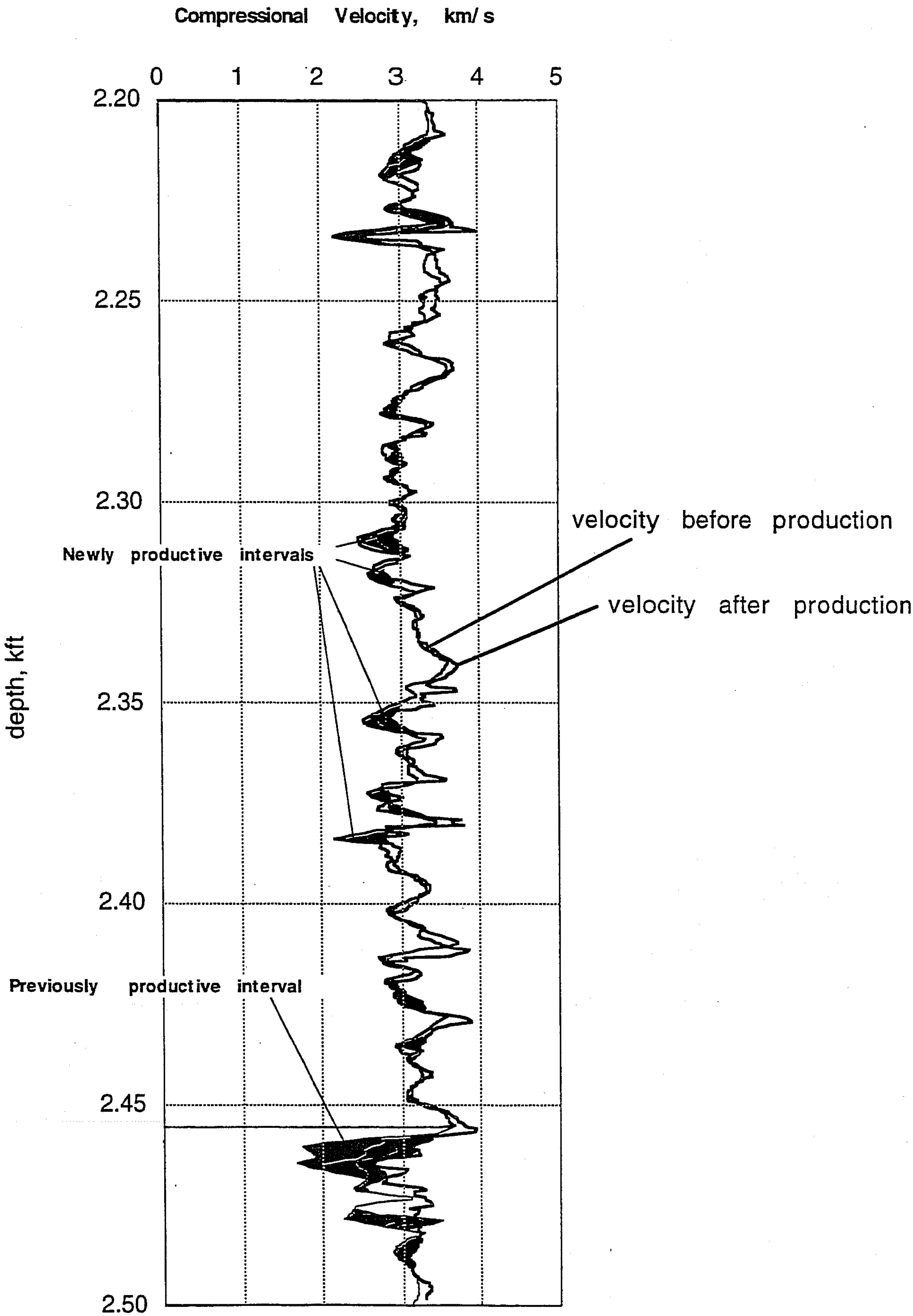


Sonic Porosity in Unconsolidated Clastic Rocks



- Replaces density porosity
- More accurate in washed-out intervals
- Can also provide saturation estimation

Acoustic Logs Detect Bypassed Oil and Identify Watered-out Intervals



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APPLICATION OF BOREHOLE IMAGING LOGS IN THE GREEN RIVER WATER FLOOD DEMONSTRATION PROJECT

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University of Utah

John D. Lomax
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This paper is a summary of the findings and decision processes surrounding the application and interpretation of borehole imaging logs in the Green River Water Flood Demonstration Project that was part of DOE's Class 1 demonstration project that dealt with enhanced recovery methods in fluvial-deltaic environments. This project was awarded to Lomax Exploration Co., the University of Utah Research Institute and the University of Utah. Lomax has since been acquired by Inland Exploration Co., and the University of Utah Research Institute has become the Energy & Geoscience Institute at the University of Utah.

In April, 1981, a discovery well, the Federal #1-35, was drilled in the Monument Butte field in Utah (Fig. 1) and completed in the Douglas Creek Member of the Green River Formation. Development proceeded on 40-acre spacing, concentrating principally on the "D" Sandstone (Lomax terminology). Primary production was anticipated to recover 309,000 STB of oil, or 5.5% of the 5.67 million STB of the oil in place. Using primary methods, field production declined to 45 bbl/day. In order to improve the recovery of oil from this reservoir, Lomax Exploration Co. initiated a water flood. This technique had never been attempted in the vicinity of the Monument Butte field, and reservoir engineering studies had predicted the procedure would not be successful based upon reservoir heterogeneity, low reservoir permeability, the high paraffin content of the crude oil and the low energy of the reservoir.

In 1987, production of the field had declined to 30 bbl/day as the flood was initiated. The flood proved successful and, as of November, 1991, production at Monument Butte had increased to 330 bbl/day. As a result of this water flood, estimated ultimate recoverable reserves of the "D" sandstone reservoir alone have increased from 300,000 bbl to over 1.2 million bbl, and recovery has increased from 5% to an estimated 20% of the oil in place. The water flood has since then expanded to include other sandstone reservoirs in the lower portion of the Green River Formation.

The Uinta Basin developed in an asymmetric fashion which has, in general, controlled the style of sedimentation. High-angle normal faults form the northern boundary of the basin adjacent to the Uinta Mountains. This faulting resulted in a source area of relatively high relief adjacent to an actively subsiding part of the basin and the deposition of a relatively coarse-grained stratigraphic section. The southern part of the basin was a zone of low relief with sediment source areas in the Uncompahgre uplift to the south. This resulted in a relatively fine-grained sedimentary succession of fine-grained sands, silts, muds and lacustrine carbonates. The half graben structural and sedimentation style is similar to that observed in many modern (Cohen, 1990; Johnson et al., 1995) and ancient (Lambiase, 1990) lacustrine basins.

Oil and gas bearing strata of the Eocene Lower Green River Formation are largely fluvial-deltaic in nature. Sandstones were deposited along shorelines, in deltas, and in distributary and fluvial channels at the shallow margins of the lake. Carbonate units were formed in marginal lacustrine facies. Along the southern and eastern margins of the Uinta Basin, fluvial-deltaic sediments of Eocene age represent over one-third of the total stratigraphic section. In the southern Uinta Basin, oil and gas reservoirs are concentrated along an east-west paleo-shoreline that extends for a distance of about 60 miles. The southern, up dip portion of the productive area is characterized by the transition from marginal lacustrine deposits into clayey lower delta plain facies. The northern boundary of the fairway is characterized by the transition from sandy shoreline deposits to fine-grained open lacustrine rocks. The open lacustrine facies consist of non-reservoir organic-rich mudstones and calcareous claystones. The fairway is present across portions of both Uintah and Duchesne counties, where it extends from the Greater Red Wash field westward to the Brundage Canyon field. The Greater Red Wash field, discovered in 1950, occupies the easternmost portion of the fairway in which numerous marginal lacustrine sandstone and carbonate reservoirs have combined production of over 135 million STBO. The western portion of the fairway has undergone limited development and is characterized by small, localized oil fields.

Within the project area, there are two major structural trends observed on the surface, gilsonite veins and the Duchesne fault zone. The Duchesne fault zone (Fig. 1) is an east-west trending zone of surface fracturing and faulting (Ray et al., 1956). The zone has been traced for a total distance of 42 miles and has a width of up to 2 miles. The mapped fault zone is located to the north of the Monument Butte unit, approximately through Lomax's Boundary Unit. There is little information published on its character. Nielson et al. (1993) showed that fracturing associated with the Duchesne fault was prominent in the Duchesne oil field and had important controls on production of oil from that field.

This project was initiated with the U. S. Department of Energy to improve the characterization of the sandstone reservoirs. One of the principal questions to be addressed was why the water flood had worked while conventional wisdom was that it would not. Initially, the depositional origin of the reservoirs was poorly understood and all the sands were thought to be of fluvial origin. Correlation of sandstone bodies between adjacent wells was often difficult. Fracturing was not thought to play a significant role in reservoir heterogeneity in this part of the basin.

Although a few sidewall cores and spot cores had been collected and analyzed, the character of the reservoir sandstones was essentially unknown. Most wells had been logged and correlations and interpretation of sedimentary facies was largely based on the gamma ray and porosity logs. The sandstone reservoirs proved to be discontinuous and correlations between wells were often in doubt; however, the large number of reservoir units has allowed most wells to be completed for production.

In addition, one reservoir unit in particular was difficult to understand. This unit, termed the Lower Douglas Creek, could reach net sandstone thicknesses of nearly 200 feet, but it tended to be very discontinuous. In addition, even though it was nearly always oil saturated, production was not predictable. It was initially decided to evaluate this unit by the collection of a continuous core and the running of a borehole imaging log. Schlumberger's Formation MicroScanner™ log was new at that time and was selected. This is a high-precision electrical resistivity imaging tool with a total of 192 micro resistivity sensors. The sensors are arranged on four arms and provide approximately 80% coverage of an 8-inch diameter well. Although this was the principal focus of the imaging log study, it was later expanded to address the other important reservoirs.

The difficulties in implementation at that time have probably been eliminated; the only real problem was the availability of the tool. At one time, the tool we used was the only functioning FMI tool, on-shore North America. However, other procedural problems were later encountered, including the service company losing the imaging log for one of the wells. We have to recommend that whenever these logs, or any other logs for that matter, are run, you should always get a digital copy. These logs are expensive to collect, and all copies should be archived in a digital format.

Borehole imaging logs coupled with a quantitative interpretation is a very powerful technique for both exploration and reservoir development applications. The FMI evolved from the dipmeter log that was traditionally used in structural interpretations. However, their application in analysis of sedimentary environments is particularly useful (Nielson et al., 1992).

In this project, imaging logs were used to determine sedimentary structures, depositional facies, and paleo-current directions to evaluate depositional environments and sand body geometry. We also use these logs to determine the character and orientation of fractures. We have found it more useful to plot orientation data as dip angle or dip azimuth as a function of depth (Bengtson, 1981; Nielson et al., 1992) rather than the more traditional dip-arrow plot. We also use the dip versus azimuth (DVA) cross plot of Bengtson (1981) to help characterize stratigraphic orientation data. In general, all data used for stratigraphic interpretation will have the structural dip removed, restoring orientation, as much as possible, to that of the depositional environment.

Core and imaging logs from well Travis 14A-28 proved to be very valuable for calibrating borehole images with real rock. The section cored was from the Lower Douglas Creek (LDC) unit that had proved to be frustrating to interpret. The core demonstrated that the unit was largely made up of turbidites (Lutz et al., 1993), an unusual occurrence for the shoaling margin of a lake. The core is comprised of two packages of planar-laminated fine-grained sandstone that exhibit various degrees of dewatering and soft-sediment deformation, which are separated by thin disrupted or massive very fine grained sandstone and siltstone beds (Fig. 2). The planar-laminated sandstones occur in 15 ft thick packages with an intraclast-rich base and a dewatered top, and are interpreted as moderate to low-density turbidite channel deposits. One of the packages, from 5632.7 to 5623.5 ft forms a complete Bouma sequence (Bouma, 1962). Both of the planar-laminated sandstone units are strongly oil-stained. Another interesting aspect of the core and image log was that the unit contained numerous fractures. The image log allowed the strike and dip of these fractures to be mapped. The core demonstrated that the fractures contained oil.

The "D" sandstone is the principal target for water flood in the project area. A discontinuous channel sandstone, the "D_2" is only of minor importance. However, the "D_1" sandstone is thick, widespread and continuous as shown on the net sandstone isopach map (Fig. 3). Although no continuous core of the D_1 Sandstone has been taken, detailed description of the sandstone is possible from the FMI image logs from two wells. Through identification of sedimentary structures and bedding contacts on the images, the FMI logs can be used to create a lithologic log and to interpret depositional facies, just as this information would be obtained from a core description. In addition, the borehole imaging logs can be used to orient features such as fractures and bed boundaries and allow the estimation of fracture apertures and sandstone bed thicknesses.

Petrography of sidewall core plugs from the sandstones reveals the presence of abundant rounded micrite clasts and micrite-coated quartz and feldspar grains that suggest formation of the grains in a marginal lacustrine environment and then transportation into the open lake. The overall fine grain size and lack of strong normal grading preclude deposition as channelized sands. Bed orientations from the D_1 reservoir in wells #9-34 and #10-34 interpreted from the FMI logs are summarized in Fig. 4. The data from the #10-34 shows a bedding orientation of about 80° while the orientation of beds in the #9-34 is much more scattered. This absence of strong orientation is probably a function of the high degree of reworking of the sediments.

The orientation and character of fractures from the Greater Monument Butte area was determined using core from well #14A-28 and FMI logging. A typical example of a fracture imaged in reservoir units is shown in Fig. 5. In general, fractures are developed in sandstones and are terminated or decrease in intensity in overlying and underlying shales. Thus, they tend to develop in the more brittle lithologies and are either not formed or preserved in the more ductile units. In most cases, there is no offset of bedding associated with the fractures, and they are more appropriately termed joints. These fractures contribute to horizontal permeability within the sandstone reservoirs, but have little influence on vertical permeability.

The orientation of fractures determined by interpretation of the FMI log from the five wells that were part of this project are shown in Fig. 6. These fracture orientations generally correspond with the F_2 trend of Verbeek and Grout (1992). The east-northeast strike of the fractures is similar to the regional east-northeast trend of faults that cut outcrops of the Green River Formation in the southern part of the Uinta Basin. The strong east-west trend in Monument Federal #9-34 is more closely parallel to the Duchesne fault zone.

The orientations of all the fractures measured in the imaging logs are shown in Fig. 7. This diagram illustrates the preponderance of steep fractures. From a statistical standpoint, there is a low probability of intersecting a steeply dipping fracture with a near vertical well. We therefore suspect that the sandstone reservoirs, where the measured fractures predominantly occur, are pervasively fractured.

The petroleum reservoirs of the lower Green River Formation owe their character to both sedimentary and structural processes. We have used borehole imaging techniques in combination with continuous and sidewall cores and interpretation of conventional logs. The aspects considered in the interpretation of the borehole imaging logs includes fracture character and orientation and identification of sedimentary features and their orientation. The borehole imaging logs also allow the identification of thin beds that are candidates for future development in this part of the Uinta Basin.

From a scientific standpoint, the imaging logs run during this project were highly successful. However, their high cost and the cost of interpretation resulted in their limited application.

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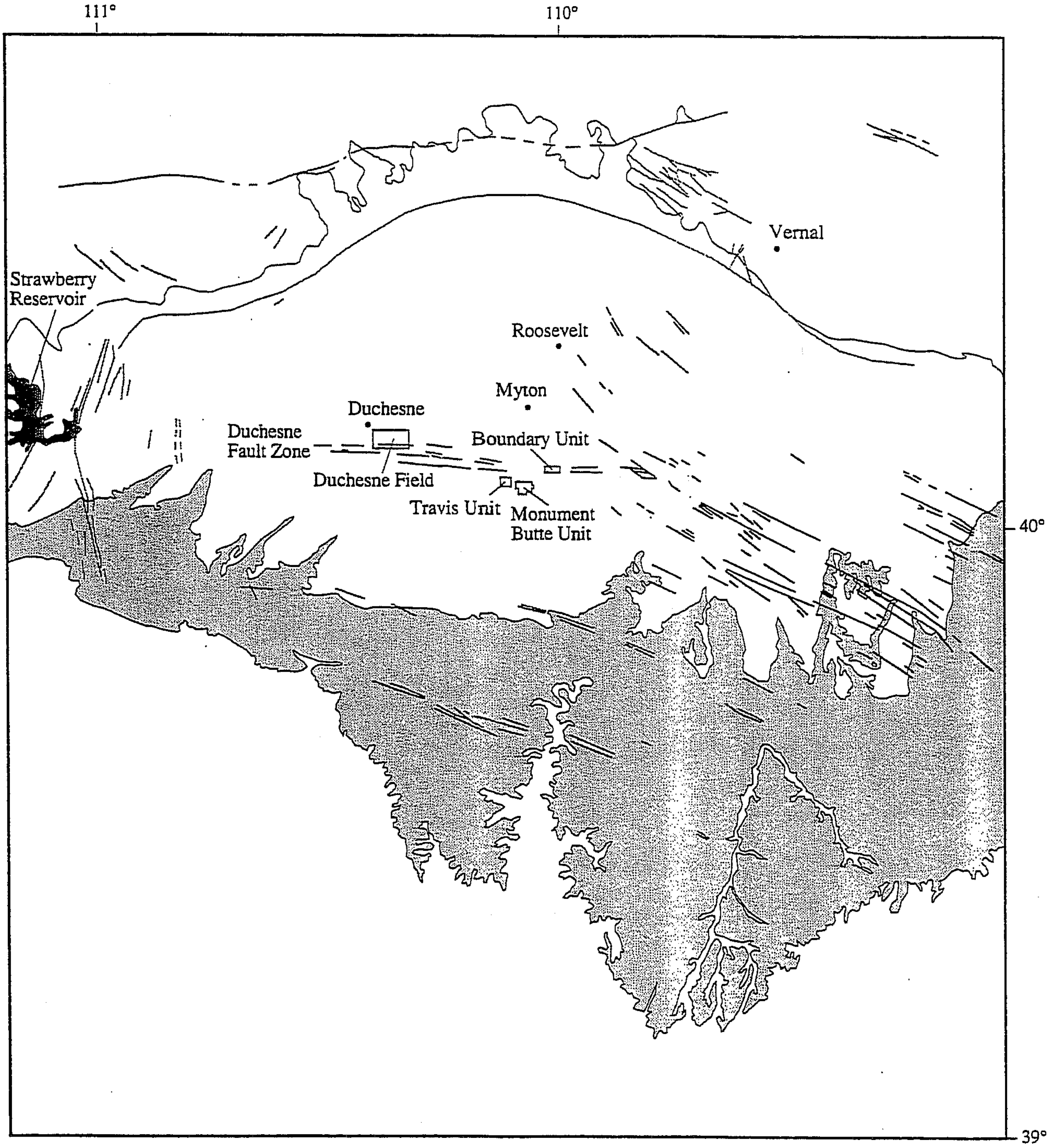

Figure 1. Map of the Uinta Basin showing major faults (light dashed lines) and gilsonite veins (heavy dashed lines) after Hintze (1980).

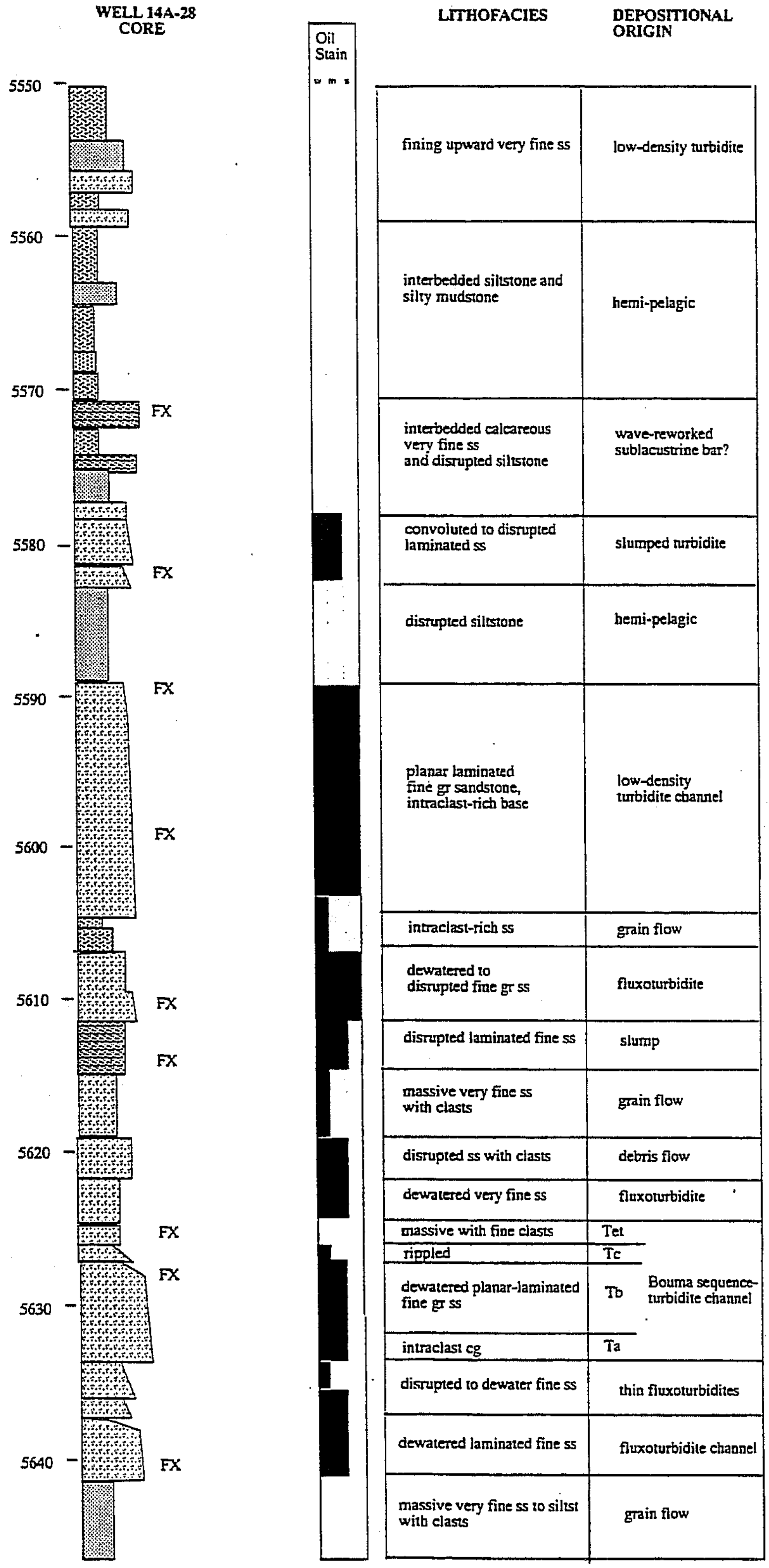

Figure 2. Summary of core from the Lower Douglas Creek unit from well Travis Federal #14A-28

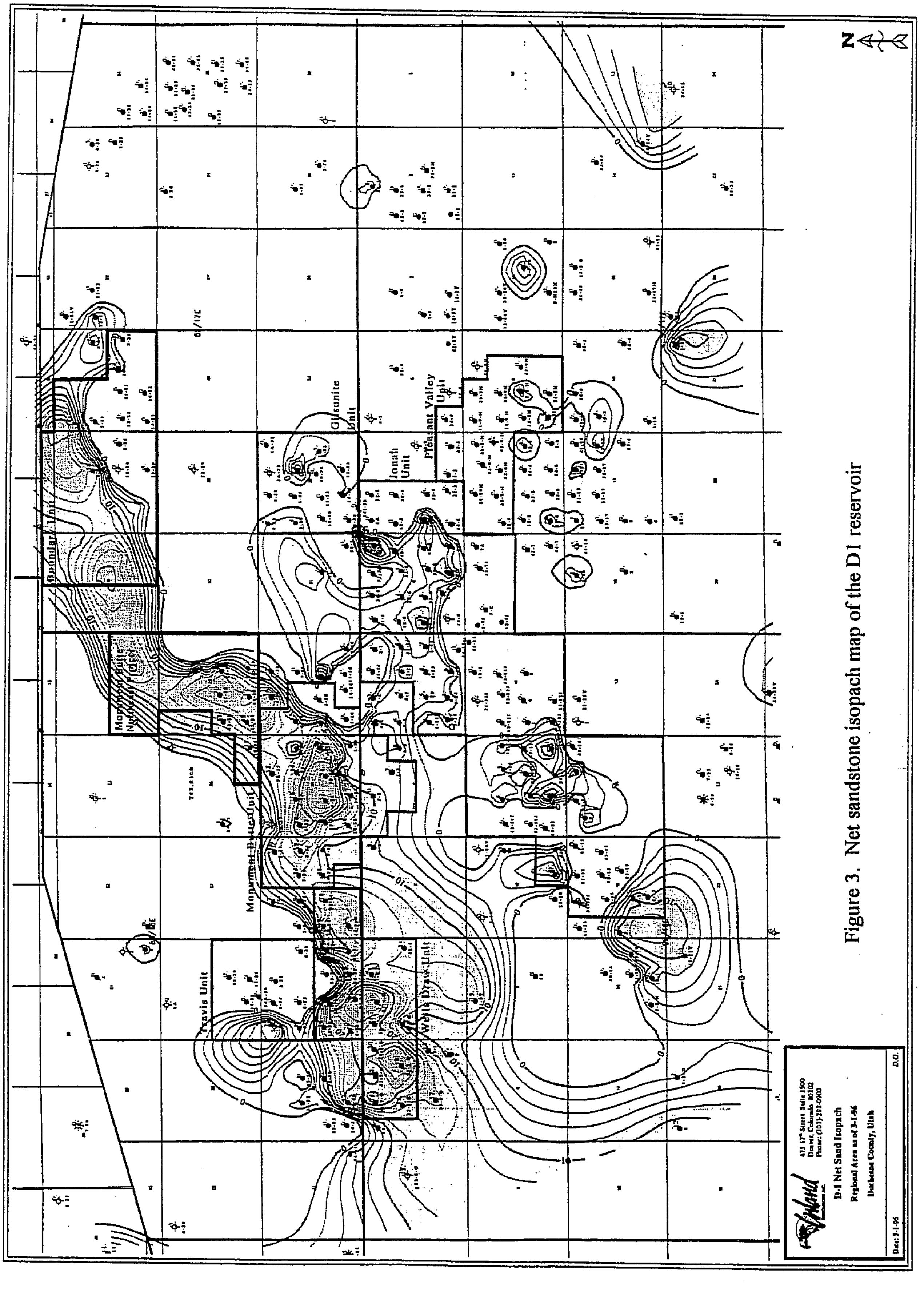

Figure 3. Net sandstone isopach map of the D1 reservoir

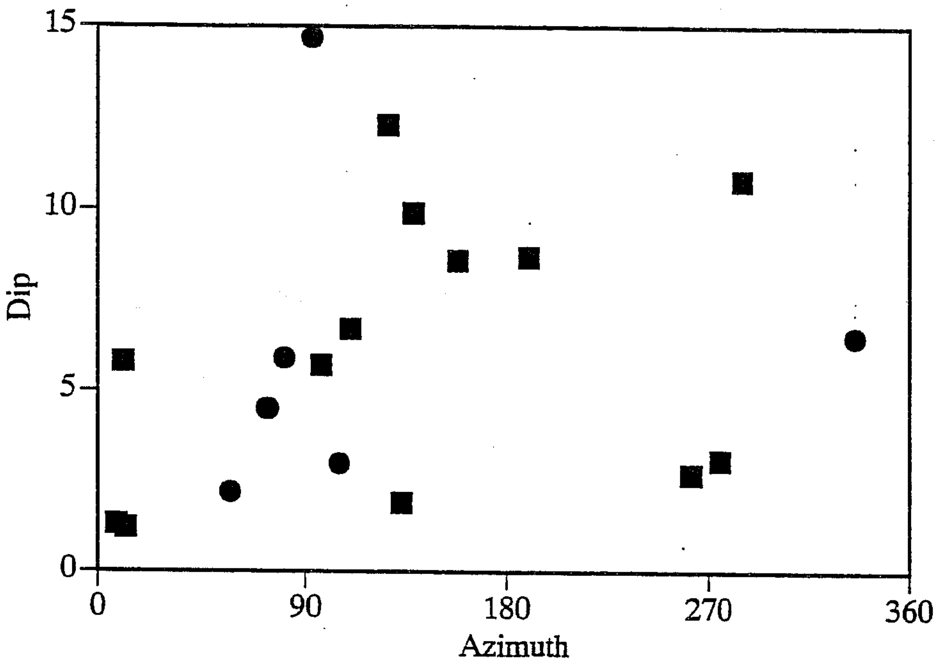

Figure 4. Dip versus azimuth (DVA) plot of bed orientation from the D1 reservoir in wells Monument Federal #9-34 (squares) and #10-34 (circles).

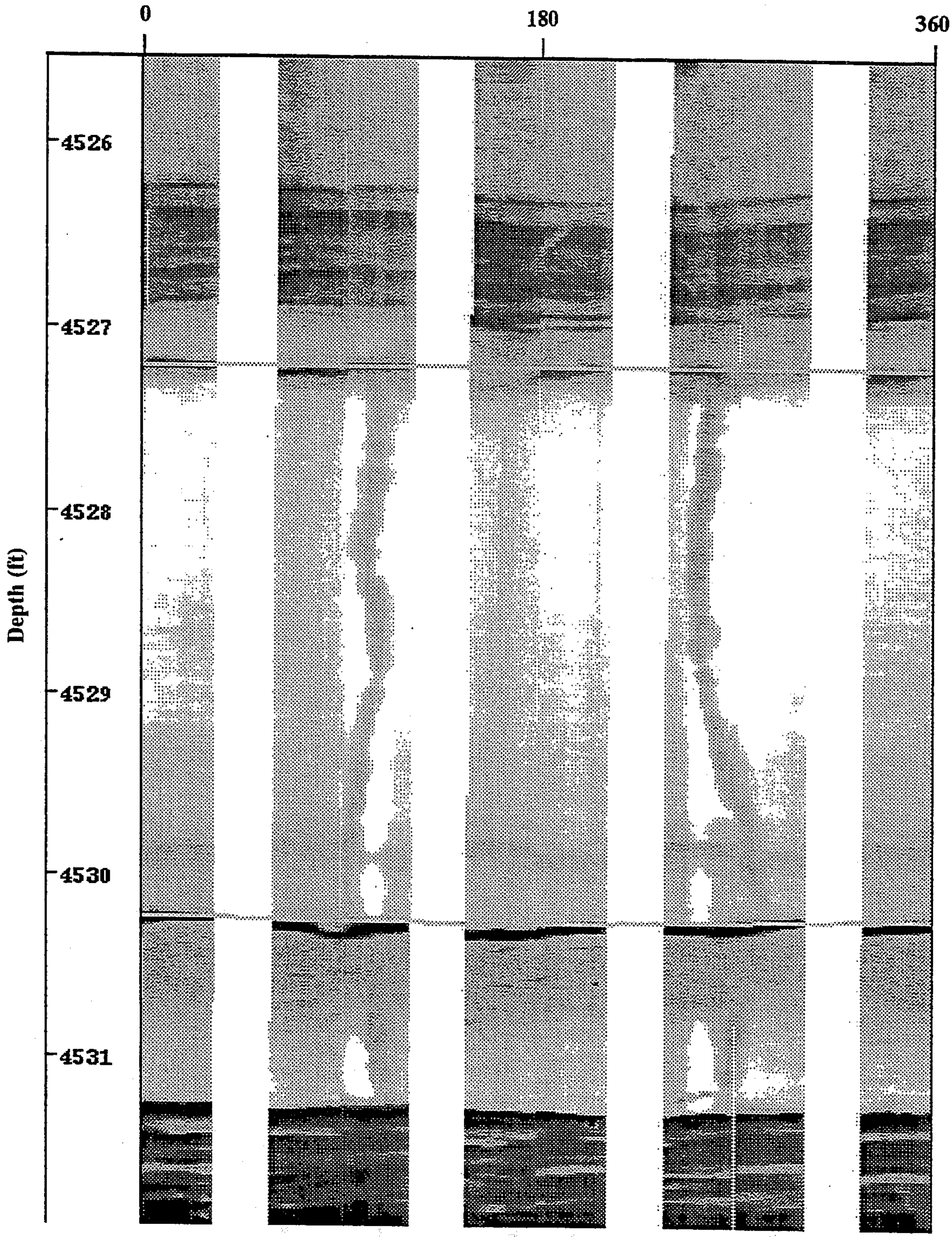

Figure 5. FMI image of stratigraphically bound fracture from Travis Federal #5-33

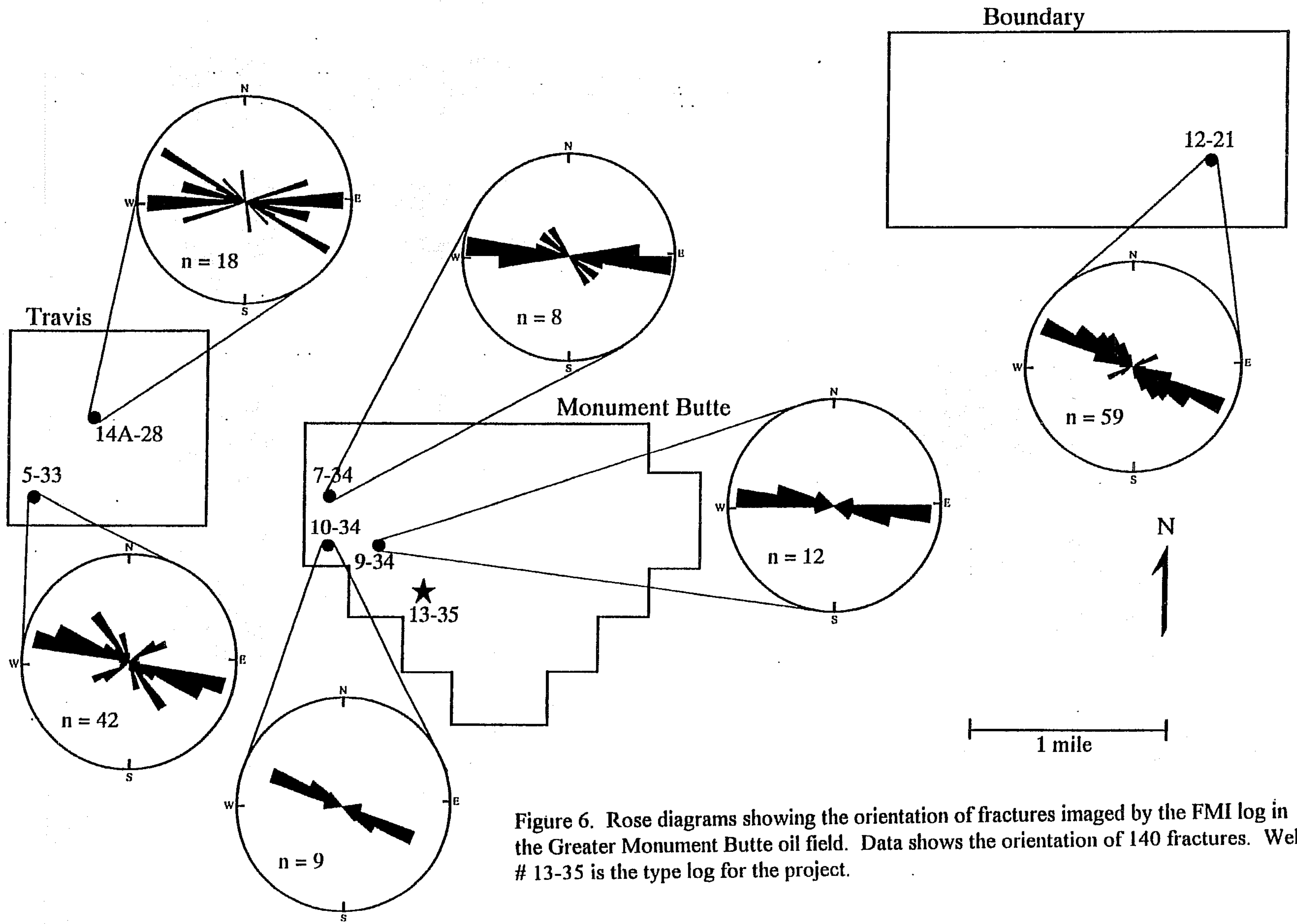

Figure 6. Rose diagrams showing the orientation of fractures imaged by the FMI log in the Greater Monument Butte oil field. Data shows the orientation of 140 fractures. Well # 13-35 is the type log for the project.

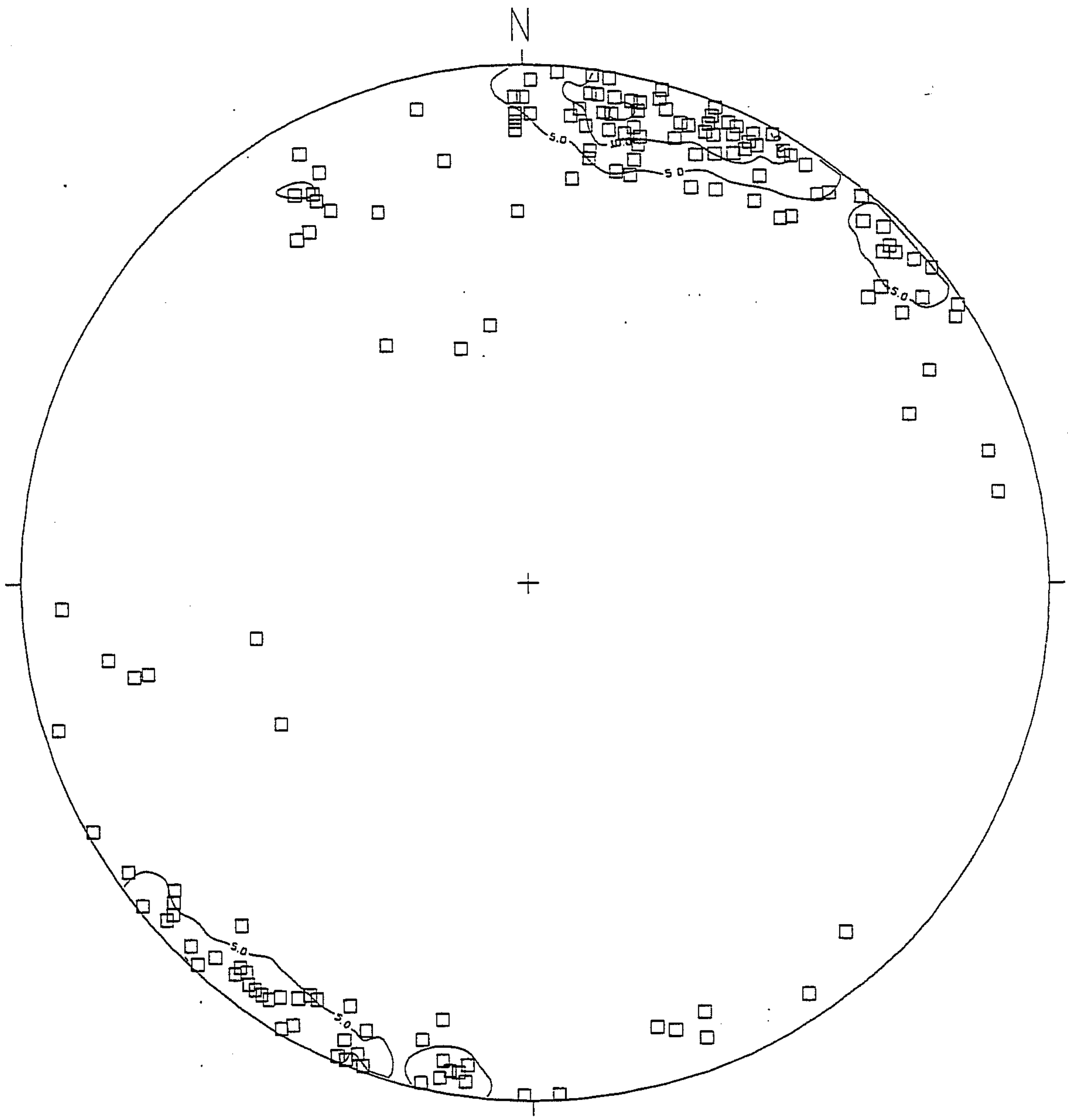

Figure 7. Equal area projection of fractures imaged by the FMI in the Greater Monument Butte Field. Contours at 5% and 10%. 165 samples.

Application of Borehole Imaging Logs to Eolian Reservoir Heterogeneity Studies, with an example from the Tensleep Sandstone, Wyoming.

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Eolian reservoirs exhibit significant compartmentalization and directional permeability caused by the processes taking place during accumulation of sediments within an eolian system. The contrast in grain packing across erosional bounding surfaces is one of the primary controls of fluid-flow patterns within eolian reservoirs. Better prediction of the geometry of flow units bounded by erosional surfaces can be made by reconstructing the type of bedform that formed the accumulation. Subsurface study of the occurrence and the frequency of erosional bounding surfaces has been limited by the availability and quality of core data. However, using borehole images, specifically FMI and FMS logs, the orientation of stratification can be resolved, and the cross-cutting relationships produced by erosional bounding surfaces can be identified. Comparison of the stratification orientation above and below an erosional bounding surface makes it possible to classify the erosional bounding surface within a process-oriented hierarchy. Using the foreset and bounding surface orientations gathered from the FMI and FMS log data, and using computer simulation methods for bedform reconstruction, a bedform that reflects the observed variations in stratification can be constructed.

An integrated study of FMS logs, FMI logs, and cores from the Tensleep Sandstone in the Oregon Basin Field, Bighorn Basin, Wyoming indicates that erosional bounding surfaces can be identified and classified. The FMI and FMS logs also allow delineation of eolian facies such as interdune accumulations.

Other information sources:

Institute for Energy Resources DOE Web site: ierultra1.uwyo.edu

Related articles:

Carr-Crabaugh, M., Hurley, N.F., Carlson, J., 1996, Interpreting eolian reservoir architecture using borehole images, *in* Pracht, J.A., Sheriff, R.E., and Perkins, B. F., (eds) Stratigraphic Analysis Utilizing Advanced Geophysical Wireline and Borehole Technology for Petroleum Exploration and Production, GCSSEPM, Seventeenth Annual Research Conference, p. 39-50.

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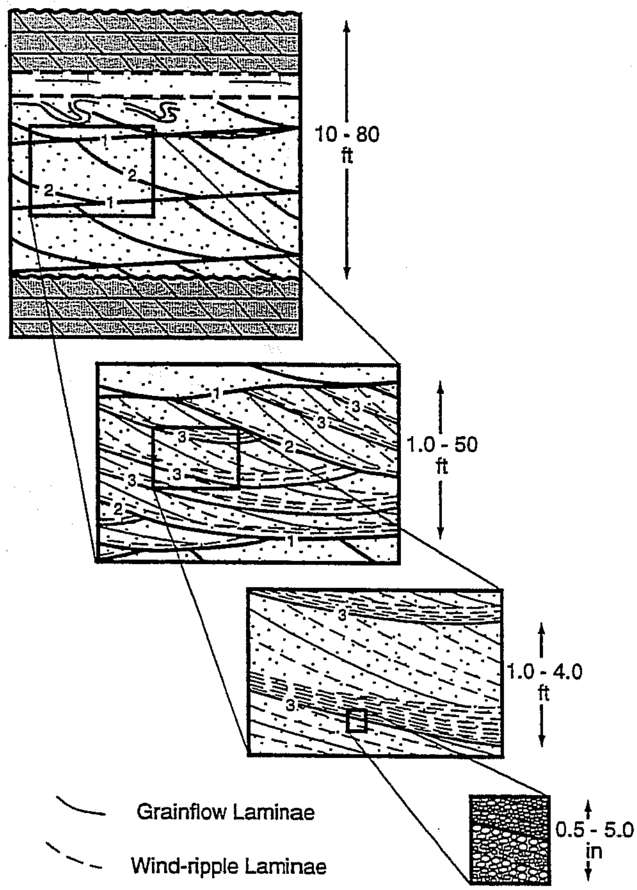

Figure 1. Illustration of different scales of reservoir heterogeneity in the Tensleep Sandstone. The largest scale of heterogeneity is defined by the marine dolomitic units, which subdivide the cross-stratified eolian sandstones. The smaller-scale heterogeneities are defined by first-, second-, and third-order erosional bounding surfaces indicated by 1, 2, and 3. Commonly, tightly-packed wind-ripple laminae overlie the erosional bounding surfaces (Carr-Crabaugh and Dunn, 1996). The tight packing results in low permeability and inhibits fluid-flow across the erosional bounding surfaces.

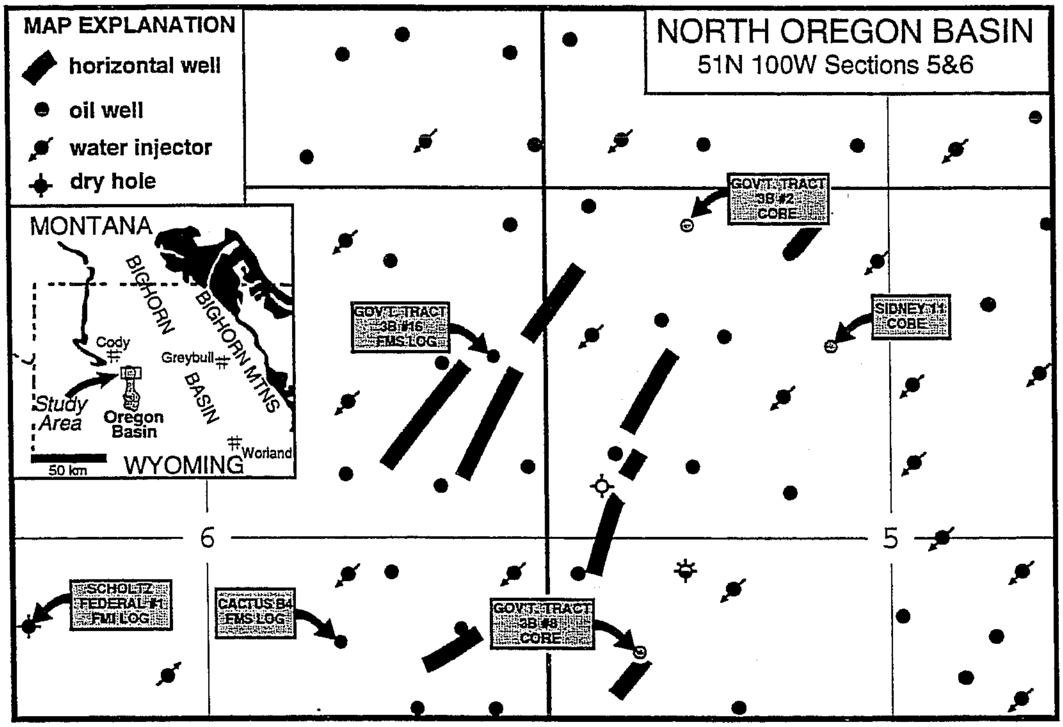

Figure 2. Map of core and well log locations in North Oregon Basin field study area. Sections are one mile on a side; quater-sections are delineated.

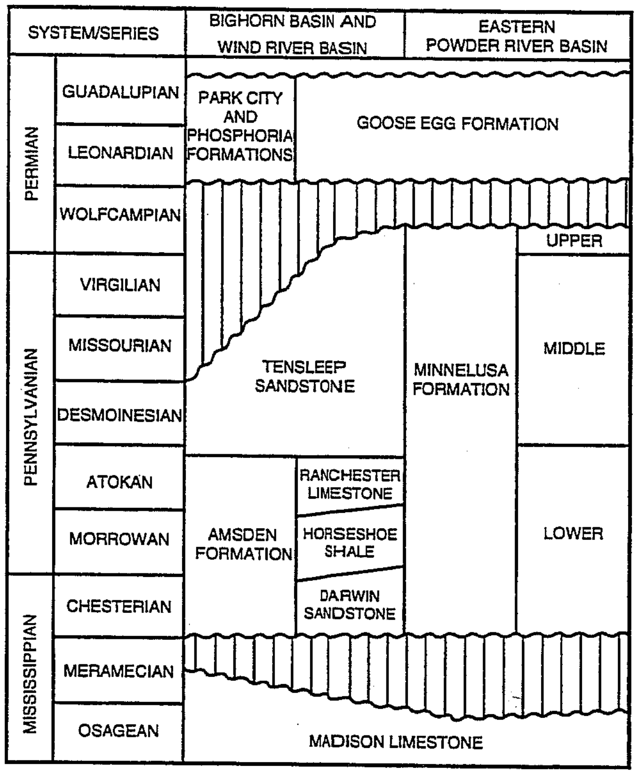

Figure 3. Correlation chart showing Mississippian through Permian units in the Bighorn and Wind River Basins. After Wheeler (1986).

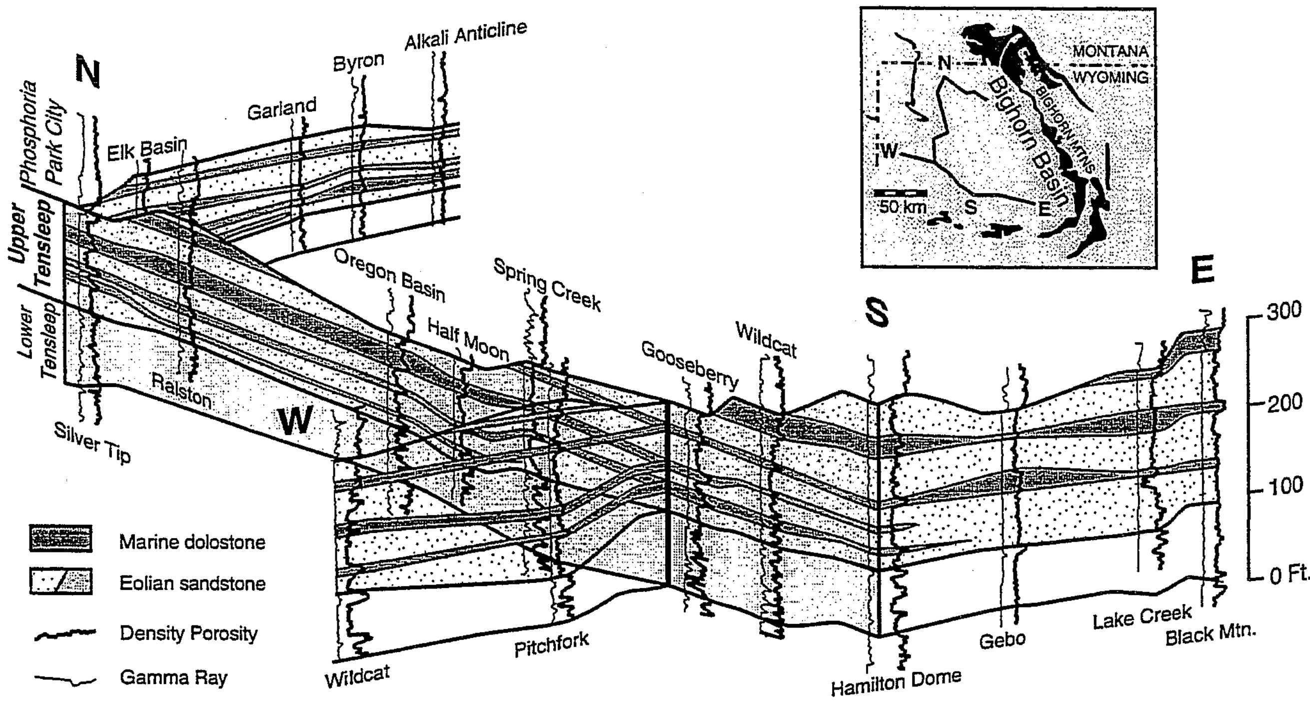

Figure 4. Fence diagram illustrating correlation of individual marine dolomitic units across the Bighorn Basin. Inset map indicates outcrop pattern of Upper Paleozoic rocks and the location of wells used in diagram. From Carr-Crabaugh and Dunn (1996).

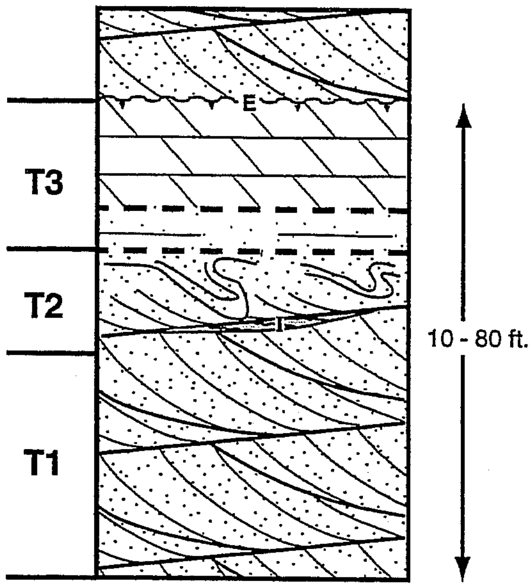

Figure 5. Idealized Upper Tensleep eolian-marine cycle. Eolian sandstone accumulation shows a thin, discontinuous interdune accumulation toward the top (I). The uppermost eolian sands are commonly contorted. The eolian sands are gradationally overlain by sandy marine dolomites, which are capped by an erosional surface (E). T1, T2, and T3 correspond to schematic diagrams in Figure 7. From Carr-Crabaugh and Dunn (1996).

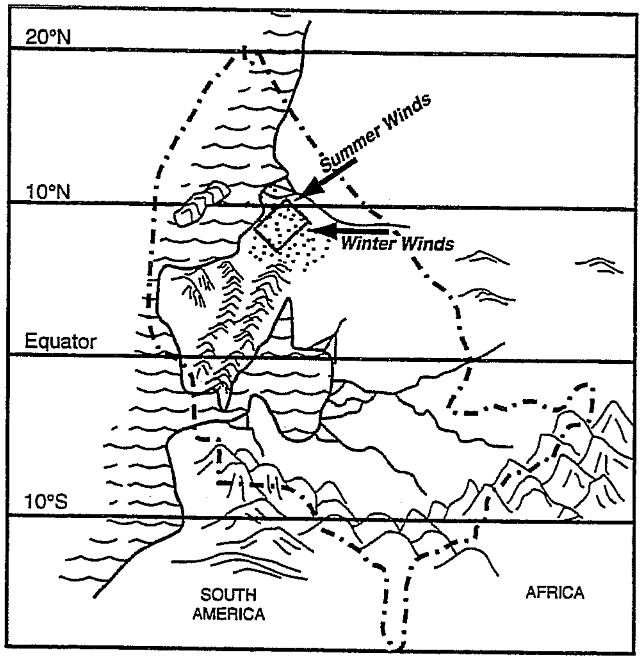

Figure 6. Generalized Pennsylvanian to Early Permian paleogeography during a sea-level lowstand. Stipple pattern indicates area of eolian development. Arrows depict paleowind directions (Parrish and Peterson 1988). Box indicates the Bighorn and Wind River Basin study area. Modified from Kerr and Dott (1988). Dashed line indicates United States border.

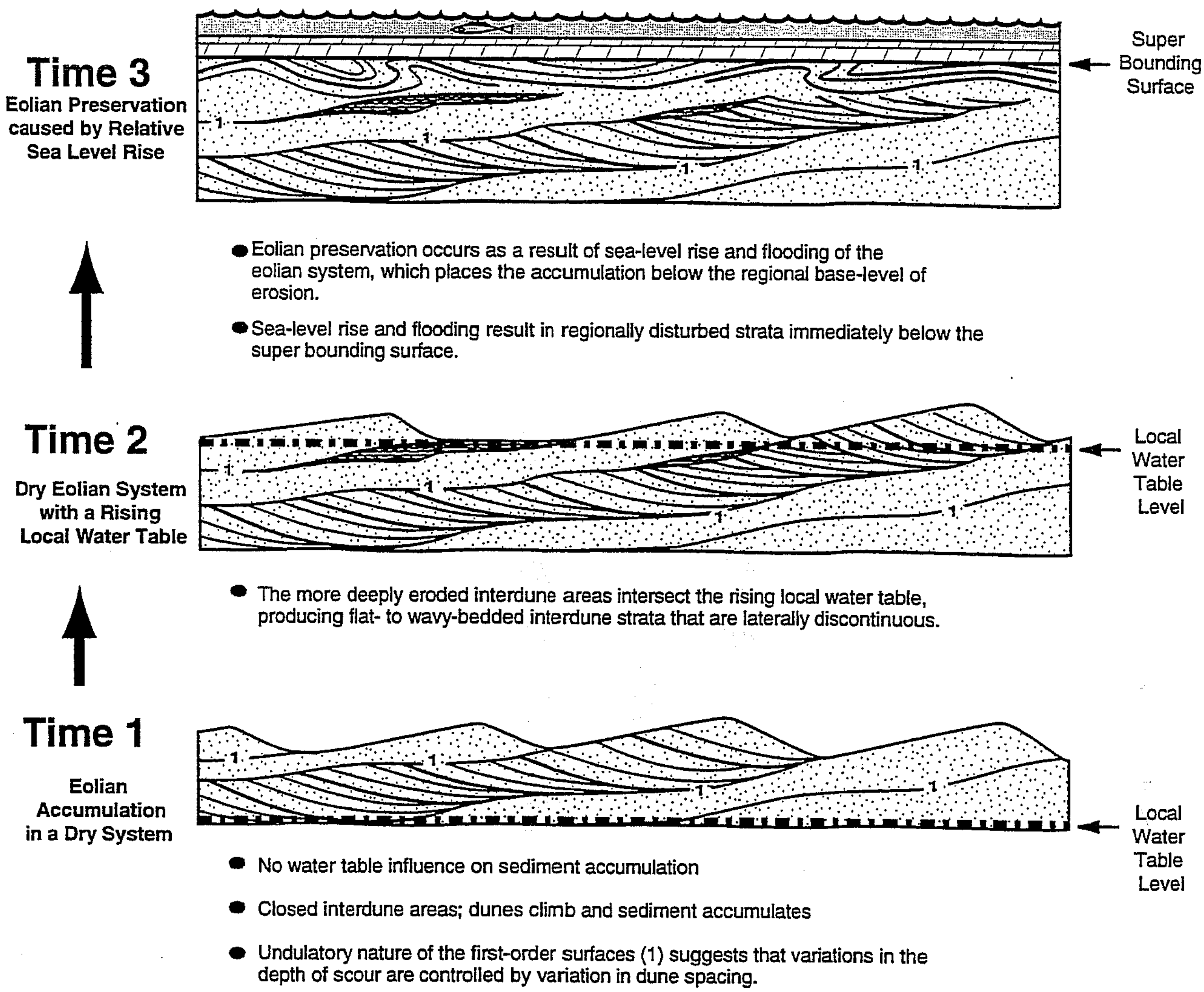

Figure 7. Schematic diagrams illustrating accumulation and preservation dynamics of the Tensleep Sandstone parallel to transport direction. Times 1, 2, and 3 correspond to T1, T2, and T3 in Figure 5. Time 1: Accumulation of sediments in a dry eolian system. The water table is well below the depositional surface and is not influencing accumulation. Time 2: Relative sea-level rise is driving up the continental water table, causing it to flood the most deeply scoured interdune areas. In outcrop, the interdune accumulations are laterally discontinuous wavy-bedded, heavily-cemented, fine-grained sandstones. Time 3: Relative sea-level rise results in flooding of the area and preservation of the eolian cross-stratified units. Contorted laminae (wavy lines) commonly occur in the upper portions of the eolian sandstone units. Subsequent relative sea-level fall results in the formation of an erosional surface capping the marine carbonates. From Carr-Crabaugh and Dunn (1996).

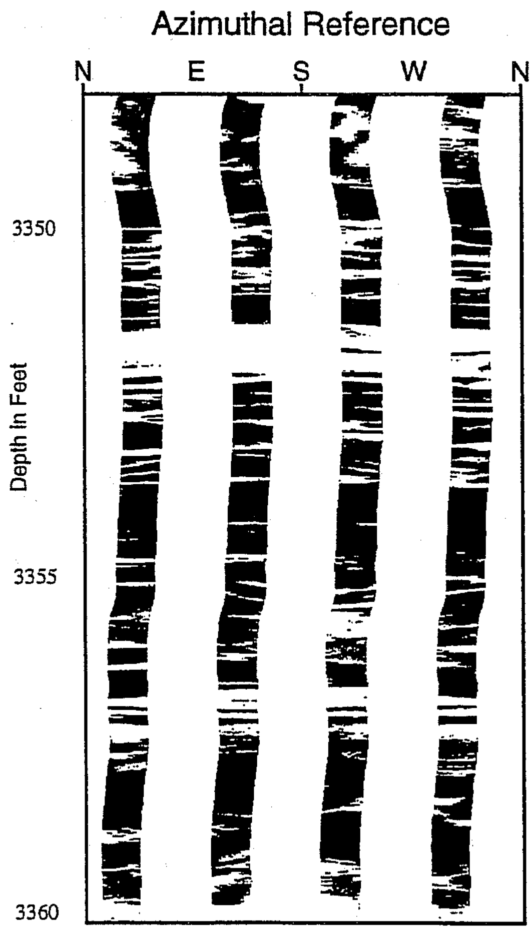

Figure 8. Uninterpreted dynamic image from the Gov't Tract 3B #16 FMS log.

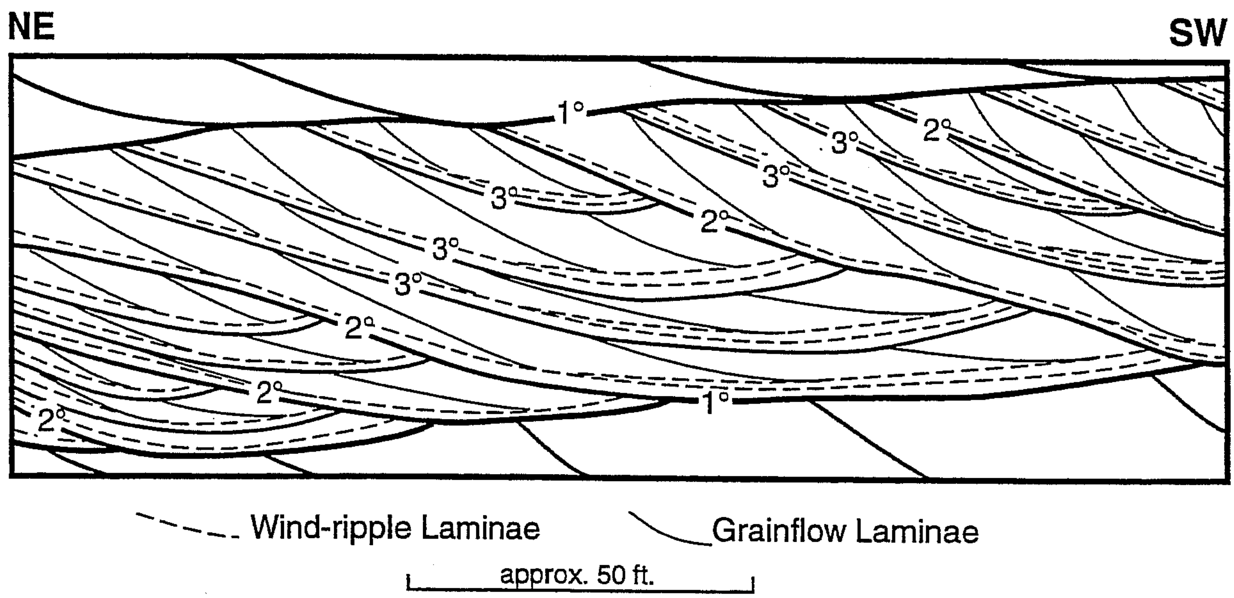

Figure 9. Schematic drawing of internal stratification within the Tensleep Sandstone illustrating the cross-cutting relationships of the first-, second-, and third-order erosional bounding surfaces.

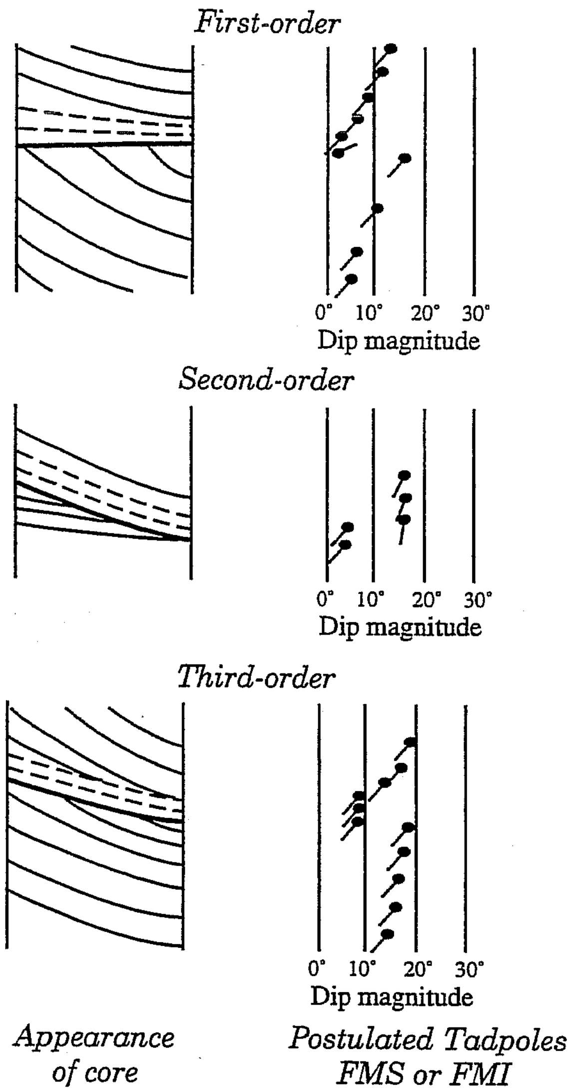

Figure 10. Comparison of types of erosional bounding surfaces observed in core and outcrop with the expected FMS or FMI tadpole arrangement. The tadpoles reflect the dip direction and dip magnitude of the associated laminae after structural dip has been removed. Dashed lines are wind-ripple laminae and solid lines are grainflow laminations.

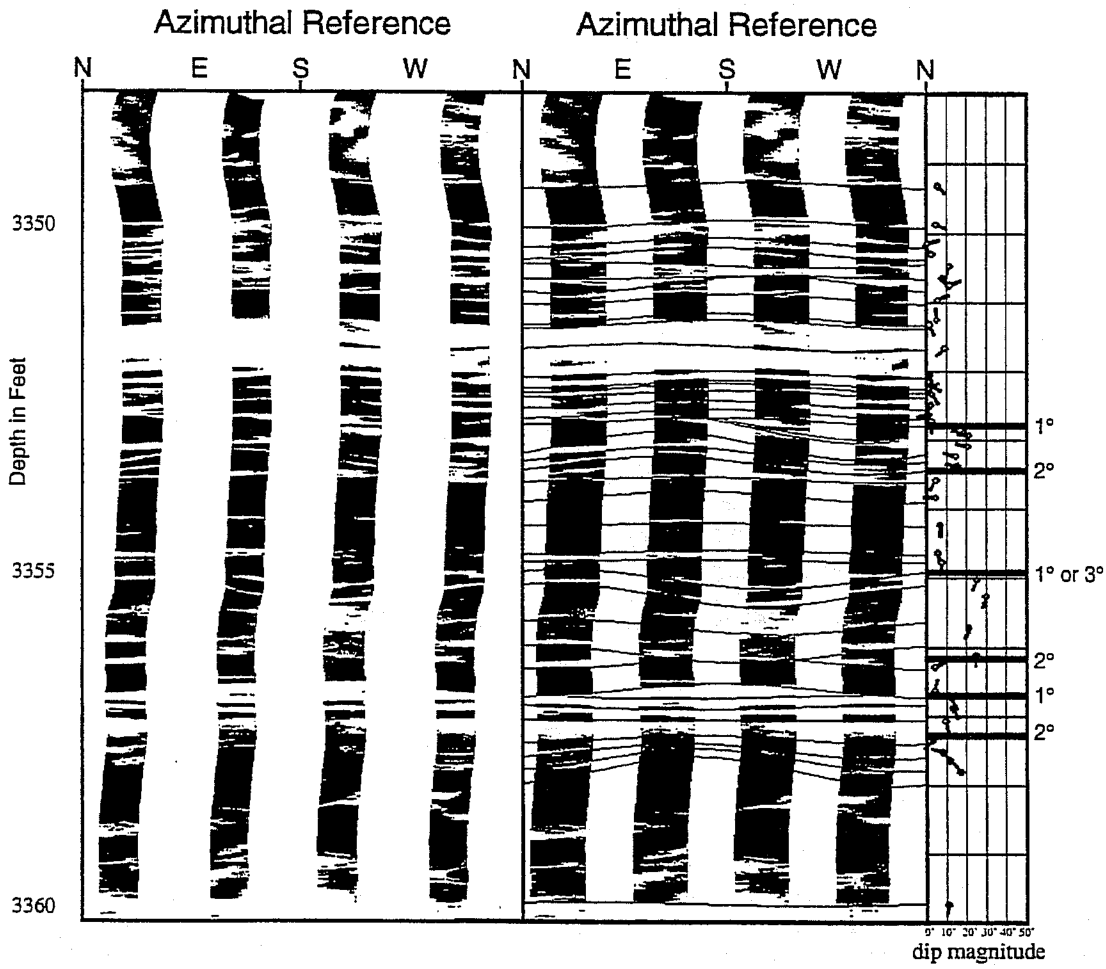

Figure 11. Interpreted dynamic image from the Gov't Tract 3B #16 well. Lines trace the intersection of foresets and the borehole. The tadpoles indicate the dip magnitude of the foresets, and point in the dip direction. Structural dip has been removed from these images. 1°, 2° and 3° indicate first-, second- and third-order erosional bounding surfaces.

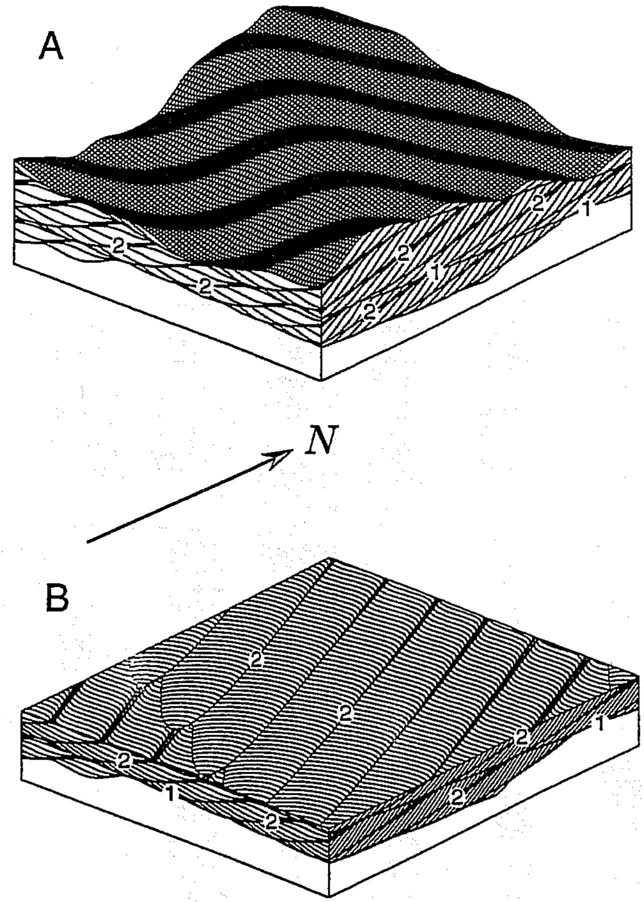

Figure 12. Portion of the Tensleep bedform reconstructed using the program developed by Rubin (1987). First-order (1) and second-order (2) bounding surfaces are labeled. **A**. The main crestline is oriented along a southeast-northwest line at 119° and is migrating to the south-southwest. Along the leeface of the main bedform, superimposed bedforms are migrating to the southeast at 145°. **B**. Stripping off the surface features allows visualization of the three-dimensional geometry of the flow-units defined by the erosional bounding surfaces.

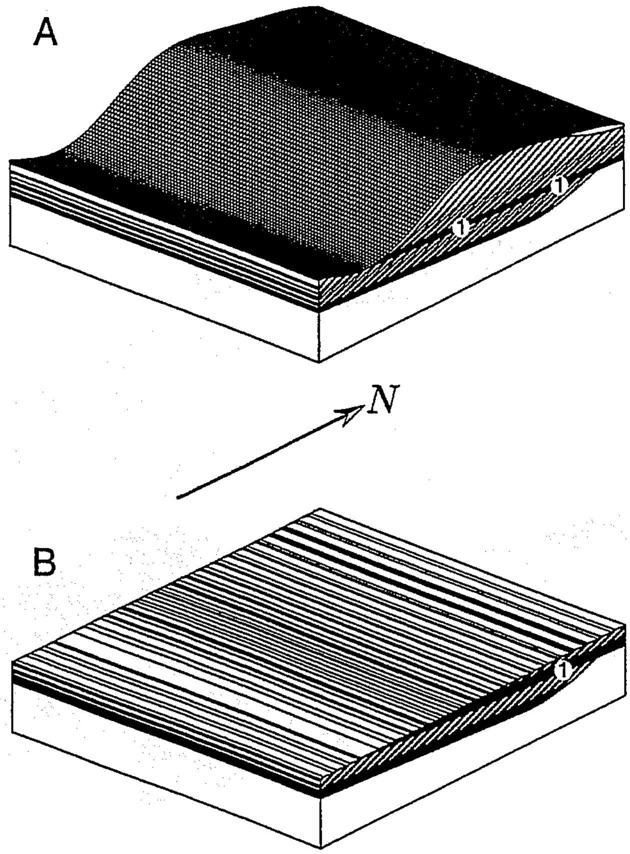

Figure 13. Portion of the Tensleep bedform reconstructed using the program developed by Rubin (1987). **A.** The main crestline is oriented along a south-north line at 90° and is migrating to the south. **B.** Stripping off the surface features allows visualization of the three-dimensional geometry of the flow-units defined by the erosional bounding surfaces.

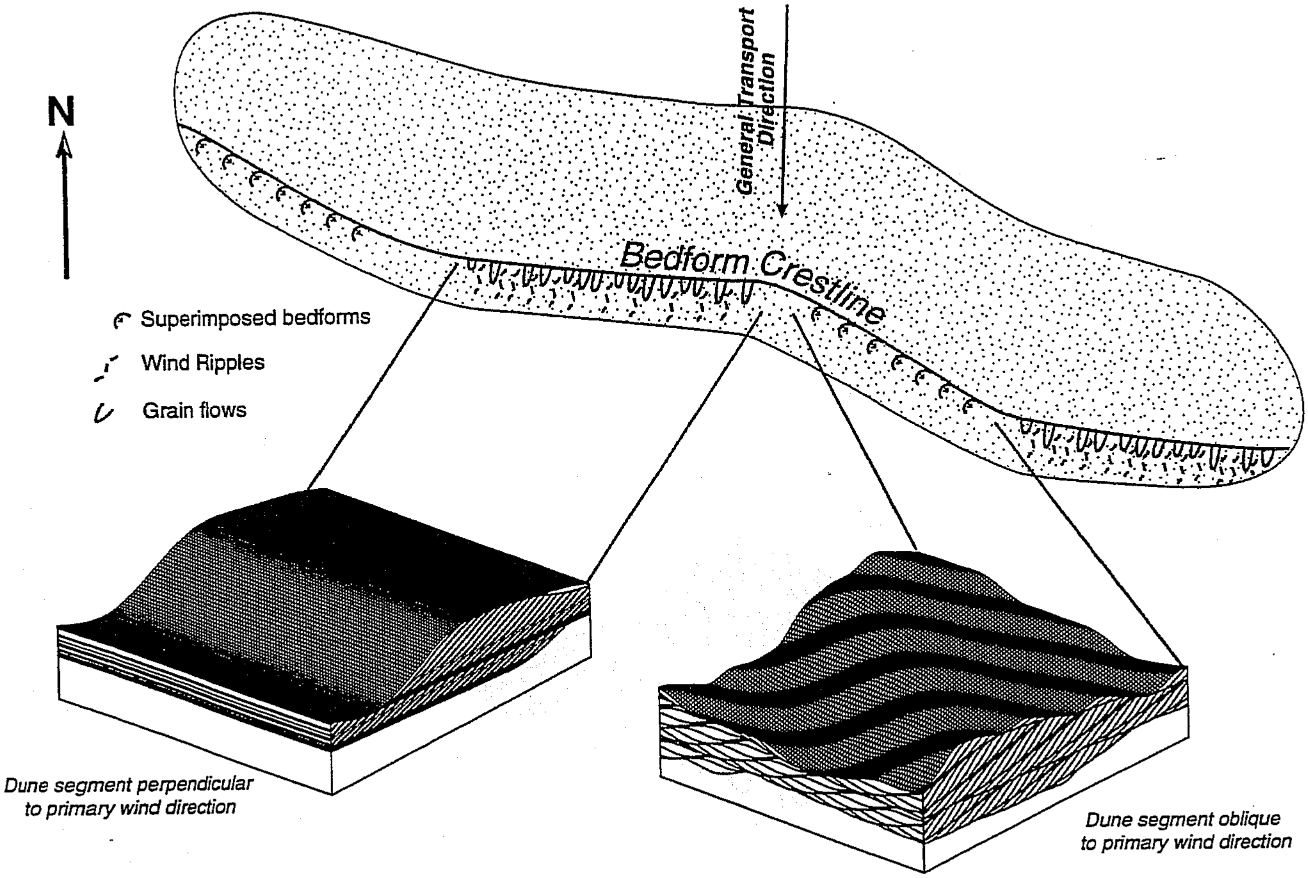

Figure 14. Idealized compound crescentic bedform, Tensleep Sandstone. Bounding surface and stratification orientations were determined and used in conjunction with the method of Rubin and Hunter (1983) to determine orientations of superimposed bedforms. The main bedform is migrating to the south, and the superimposed bedforms are migrating to the south-southeast along the arms of the main bedform oriented obliquely to the dominant wind direction.